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Board

Office national
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Canada's Oil Sands:

A Supply *and* Market Outlook *to* 2015

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ACRONYMS

AEC	Alberta Energy Company Ltd.
AENV	Alberta Environment
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CCME	Canadian Council of Ministers of the Environment
CEMA	Cumulative Effects Management Association
CFCs	Chlorofluorocarbons
CONRAD	Canadian Oilsands Network for Research and Development
CNRL	Canadian Natural Resources Ltd.
CSS	Cyclic Steam Stimulation
CT	Consolidated or Composite Tailings
DRU	Diluent Recovery Unit
EIA	Environmental Impact Assessment
EPEA	Environmental Protection and Enhancement Act
EUB	Alberta Energy and Utilities Board
GCOS	Great Canadian Oil Sands
GHG	Greenhouse Gases
IPS	Inclined Plate Settlers
MOU	Memorandum of Understanding
NEB	National Energy Board of Canada
NOSTF	National Oil Sands Task Force
OCWE	OSLO Cold Water Extraction
OSCA	Oil Sands Conservation Act
OSLO	Other Six Lease Owners
PADD	Petroleum Administration Defence District
PLA	Public Lands Act
PM	Particulate Matter
PSV	Primary Separation Vessels
RAC	Reclamation Advisory Committee
RSDS	Regional Sustainable Development Strategy
SAGD	Steam Assisted Gravity Drainage
TOR	Tailings Oil Recovery
TPG	Technical Planning Group
UTF	Underground Test Facility
VAPEX	Vapour Extraction Process
VDU	Vacuum Distillation Unit
VOCs	Volatile Organic Compounds
WBEA	Wood Buffalo Environmental Association
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

FOREWORD

The National Energy Board (the Board or NEB), as part of its regulatory mandate, is required to keep under review the outlook for Canadian supply of all energy commodities including electricity, oil, natural gas and their by-products and the demand for Canadian energy commodities in both the domestic and export markets.

As a result of the increasing level of integration within energy markets, the Board implemented a program of Energy Market Assessments (EMA) to provide analyses of the major energy commodities on either an individual or integrated commodity basis. The EMA program includes what were previously known as Natural Gas Market Assessment (NGMA) reports, as well as the *Canadian Energy Supply and Demand* reports.[1]

This EMA is the first focussing specifically on crude oil, and is entitled *Canada's Oil Sands: A Supply and Market Outlook to 2015*. The main objective of this report is to review the supply and market for bitumen and synthetic crude oil derived from Canada's oil sands, to the year 2015. In addition to the supply and market, the report also discusses the early history of oil sands development, the role of science and technology in advancing oil sands development, supply costs, pipeline infrastructure and environmental issues. The study also examines the impact of oil sands development on the natural gas and electricity markets in Canada.

For this report the Board conducted a series of informal meetings and conversations with a representative cross-section of the oil sands industry, including producers, marketers, refiners, pipeliners, industry associations, research institutions, consultants, government agencies and environmental protection groups. Several private individuals, now retired, provided valuable comment and insight.

The NEB greatly appreciates the information and comments provided and would like to thank all who participated for their time and expertise. This input played an important role in the formulation of the Board's views, and combined with the Board's own analysis provides the basis for the supply and market outlook provided in this report.

The primary purpose of this report is to provide a projection of the supply and market for bitumen and synthetic crude oil for the information of the public. It should not be perceived as a recommendation to the Minister of Natural Resources Canada, nor should it be considered to be an expression of views on energy policy matters.

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[1] Canadian Energy Supply and Demand to 2025, published in June 1999, is the most recent report.

EXECUTIVE SUMMARY

Based on publicly announced development plans covering the period 1996 to 2010, nearly C$34 billion worth of projects are planned to expand petroleum production from the oil sands, with about C$7 billion spent to date. These development plans consist of an array of nearly 60 projects that would increase the production volumes of synthetic crude oil (also known as upgraded) and bitumen, to a combined level of about 300 000 m^3/d[1] by 2010, or nearly three times current levels, assuming all projects proceed as announced. History suggests that oil prices and markets will be volatile, and it is therefore unlikely that all C$34 billion worth of announced projects will proceed as planned. The marketplace will dictate the timing and magnitude of incremental production volumes.

This report provides an assessment of the supply situation for synthetic crude oil and bitumen and the market's ability to absorb the projected supply, to the year 2015. In order to provide background for this discussion, sections on oil sands resources, oil sands pioneers, technological innovation, supply costs, pipeline capacity and environmental impacts of oil sands development are also included.

Clearly, the oil sands are a tremendous Canadian resource. The ultimate volume of crude bitumen in place is estimated to be some 400 billion cubic metres, with 12 percent or 49 billion cubic metres estimated to be ultimately recoverable — a volume comparable to the proven conventional oil reserves of Saudi Arabia.

By the early 1900s, the premise that there was a large pool of "free oil" beneath the oil sands, trapped by shale formations, was disproved by drilling. While many saw value in the oil sands as a road-paving material, and a number of paving projects were completed, transporting the oil sands from such a remote location proved to be uneconomic. As the need for transportation fuels increased, efforts to realize the oil sands value as a source of transportation fuels accelerated.

Among the oil sands pioneers, two men stood out — Sidney Ells and Karl Clark. Sidney Ells was a federal civil servant who was in large part responsible for the early exploration and delineation of the oil sands deposits. He saw the promise in the oil sands, and from 1913 until his retirement in 1954, he was a tireless champion of its development. Dr. Karl Clark was one of the first employees of the newly formed Alberta Council of Research, in 1921. His genius and dedicated research led to the successful development of the hot water bitumen extraction process that provided the basis for the extraction methodology currently used by the integrated mining plants at Fort McMurray.

The Blair Report, commissioned by the Alberta government and released in 1950, indicated that oil sands mining and bitumen extraction would be economically feasible. This, plus a more favourable provincial leasing policy, encouraged industry to pursue oil sands opportunities, both mining and in situ. This paved the way for commencement of the first integrated oil sands mining/upgrading operation in 1967, and the first commercial in situ recovery project in 1978.

Science and technology has always played a vital role in the oil sands industry, and research is ongoing into a wide variety of problem areas. Supply costs for bitumen production from Canada's oil sands have been substantially reduced through a process of continuous improvement in all aspects of operations and more importantly, through the implementation of major technological innovations, with most of these innovations occurring in the 1990s.

---

[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

A good deal of credit for the upsurge in oil sands activity in the 1990s belongs to the National Oil Sands Task Force, whose 1995 report on oil sands strategies led to the adoption of a generic fiscal regime that provides for stable and predictable royalty and tax treatment for all developers. In addition, its recommendations led to the establishment of the Canadian Oil Sands Network for Research and Development, which has very successfully promoted collaborative oil sands research efforts.

For the existing surface-mining operations, supply costs have been reduced by more than one-half in the last twenty years, with current supply costs in the field estimated to be in the range of C$15-18 per barrel. The adoption of truck and shovel mining, hydrotransport and low energy extraction are the major reasons for this cost reduction.

For in situ operations, supply costs have also been reduced through continuous improvement and innovation, although not to the same extent as in the surface-mining operations. Continuous improvement in cyclic steam stimulation (CSS) operations, the maturation of horizontal well technology and the development of the steam assisted gravity drainage (SAGD) recovery technique are the major features that have facilitated this cost reduction. Current supply costs for CSS are estimated to be in the C$10-16 per barrel range, while those for SAGD are estimated to be C$8-14 per barrel. Costs for both methods are highly dependent on the quality of the reservoir.

Both integrated mining projects and thermal in situ projects use substantial amounts of natural gas as a fuel source in their operations. Thus, the price of natural gas is an important determinant of the level of profitability for these projects. The cost of condensate for blending of bitumen is also an important consideration.

In regard to primary recovery, the development of extended-reach and multi-leg horizontal wells facilitated the economic recovery of bitumen in the Wabasca region. In the Cold Lake region, the adoption of the progressive cavity pump in vertical well bores reduced the cost of production. Estimated supply costs for Wabasca are C$7-10 per barrel, compared to C$10-13 per barrel for Cold Lake.

The supply projections use the economic assumptions contained in the Board's Canadian Energy Supply and Demand Report to 2025 (Supply and Demand Report) including a US$18 per barrel price for benchmark West Texas Intermediate (WTI). The assumption is made that the supply projections are unconstrained by markets or pipeline capacity. Similar to the Supply and Demand Report, price sensitivities at US$14 and US$22 were included to gauge the relative response of production to price.

In the Base Case, synthetic crude oil production is projected to increase nearly three-fold compared to current levels, reaching 158 000 m^3/d by 2015. Similarly, bitumen production is projected to increase by two and one-half times current production by 2015, reaching 104 000 m^3/d by 2015. Considering the declining trend in conventional heavy and conventional light crude oil production in Western Canada, oil sands production could be over 50 percent of total Canadian crude oil production by 2015.

A shortfall of pentanes plus for purposes of blending bitumen could occur as early as 2005, given the Base Case supply projections. This problem has the potential to constrain bitumen production, given that solutions currently available represent a significant added expense for producers.

The net available supply of Canadian crude oil, in the Base Case, rises to 502 000 m^3/d in 2008, then gradually declines to about 490 000 m^3/d by 2015. In the $22 Sensitivity, the net available supply includes production from the Mackenzie Delta-Beaufort Sea region and reaches a peak of about 606 000 m^3/d before declining slightly by the end of the projection period. In the $14 Sensitivity, the net available supply decreases to 314 000 m^3/d by 2015, or about 5 percent below current levels.

An assessment of natural gas requirements and electrical power generation related to oil sands development indicates that gas requirements would double to nearly 1 bcf/d by 2015, and that about 4.8 TW.h of generating capacity would be available to the Alberta power grid, also by 2015. This represents about 7 percent of Alberta's 1999 gas production and about 9 percent of its 1999 power generation capacity.

Based on the estimated increased production of synthetic crude oil and bitumen over the next 15 years, it is expected that additional trunkline capacity will be added. Proposed expansion plans have been announced by Express and Enbridge to serve key markets in Ontario, as well as in PADD II and PADD IV in the U.S. This will increase trunkline capacity by 45 900 m^3/d by January 2004, if all announced pipeline proposals proceed.

An opportunity for Canadian producers to sell their increasing outputs of synthetic crude oil and blended bitumen is developing in the North American marketplace. Product demands are growing and more crude oil will have to be processed to satisfy these requirements. As well, conventional light and conventional heavy crude oil production in both Canada and the U.S. is expected to decline during the projection period.

The Board's assessment of available markets for synthetic crude oil indicates that the increased production will likely be absorbed in the marketplace, although some price discounting relative to other light crude oils could be required. In the $22 Sensitivity, production of synthetic crude oil is about 14 percent higher than in the Base Case; the Board believes that these quantities could be marketed, but the price discount would likely have to widen. Marketing would not be an issue in the $14 Sensitivity because there would be substantially reduced production of synthetic crude oil.

In the case of blended bitumen, marketability appears to be somewhat less certain than that for synthetic crude oil, and it is conceivable that temporary supply imbalances could occur. The Board believes, however, that in these situations there would be a widening of the light/heavy crude oil price differential, which would provide the incentive to install upgrading facilities and, in turn, eliminate the supply imbalances. In the $22 Sensitivity, production of blended bitumen would be 30 percent greater than in the Base Case. In this situation, it is unlikely that the market could absorb these volumes. Again, marketing would not be an issue in the $14 Sensitivity because of significantly reduced output of blended bitumen.

The increasing project development currently underway or proposed will bring with it many challenges for the industry, the public and the regulators. Careful planning is required to ensure that no irreparable damage is done to the people and the environment, and that natural resources are developed in a sustainable manner taking into account the needs of the future generations. Although, in general, technological improvements have reduced environmental impacts on a per unit basis, cumulative environmental impacts may increase as overall production increases. The many multi-stakeholder groups established over the last several years will be critical to managing the cumulative effects of increasing development in the oil sands region. In addition, the Regional Sustainable Development Strategy and subsequent development of management programs—a new and innovative approach to managing the cumulative effects of an industry—will need to be closely scrutinized for their effectiveness.

CHAPTER ONE

INTRODUCTION

"That this region is stored with a substance of great economic value is beyond all doubt, and when the hour of development comes, it will, I believe, prove to be one of the wonders of northern Canada."

These words, attributed to the chronicler of the Geological Survey of Canada's (GSC) Liard expedition of 1889, certainly ring true today, as the oil sands industry is entering an era of unprecedented growth.

Clearly, the oil sands are a tremendous Canadian resource. The ultimate volume of crude bitumen in place is estimated to be some 400 billion cubic metres[1], with 12 percent or 49 billion cubic metres estimated to be ultimately recoverable[a] — a volume comparable to the proven conventional oil reserves of Saudi Arabia.

Based on publicly announced development plans covering the period 1996-2010, nearly C$34 billion worth of projects are planned to expand production from the oil sands, with about C$7 billion spent to date. These development plans are comprised of an array of nearly 60 projects that include: expansions of existing integrated surface-mining/upgrading plants; new mining and upgrading facilities; in situ and primary production projects; new pipelines and expansions of existing pipelines; co-generation plants (electrical power and steam) and other related facilities. The production of synthetic or upgraded crude oil and bitumen, assuming all projects proceed as announced, will reach a combined level of about 300 000 m^3/d, or nearly three times current levels by 2010.

Reasons for this upsurge in oil sands development include:

- a sharp reduction in operating costs, over the last decade, for integrated surface mining/upgrading projects — due in large part to the development and adoption of new technology;
- the development of the steam assisted gravity drainage (SAGD) method for in situ bitumen recovery;
- advances in horizontal well technology;
- the establishment of a generic fiscal regime that provides for stable and predictable royalty and tax treatment for all developers;
- a growing North American market opportunity resulting from declining domestic conventional crude oil production levels in both Canada and the United States combined with increasing demand; and,
- strong recent crude oil prices and optimism regarding future oil prices.

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[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

The National Oil Sands Task Force deserves a good deal of credit for providing considerable impetus to the recent pace of development of the oil sands industry. The Task Force was formed in 1993 by the Alberta Chamber of Resources and included representation from operating companies, research agencies, suppliers, as well the federal and provincial governments. This group released a major report in 1995, that set out a vision for oil sands development.[b] This vision emphasized collaboration by all stakeholders, investment in science and technology, and environmental protection. The group also recommended changes to the fiscal regime and regulatory framework, as well as improvements to market access and transportation systems.

Many of the Task Force recommendations have been acted on, including changes to the fiscal regime for oil sands. The establishment of the Canadian Oil Sands Network for Research and Development (CONRAD), to coordinate oil sands research efforts has proven to be very successful.

History suggests that oil prices and markets will be volatile, and it is therefore unlikely that all C$34 billion worth of announced projects will proceed as planned. The marketplace will dictate the timing and magnitude of incremental production volumes.

The primary purpose of this report is to provide an assessment of the supply situation for synthetic crude oil and bitumen and the market's ability to absorb the projected supply. The impact of the projected oil sands developments on natural gas and electricity requirements is also examined.

To support the discussion of supply and markets, the report begins with some background information, including:

- a summary of important events and individuals that shaped the early oil sands history;
- a review of the crude bitumen resource base and the important characteristics of the oil sands deposits and the bitumen contained therein; and,
- a review of the methods and technologies employed in current oil sands operations, in the context of a comparison of new versus old to highlight the important innovations, and a review of current research efforts to highlight the importance of science and technology.

The core of the report provides a review of:

- supply costs for the various types of bitumen recovery and upgrading methods, including a discussion of the fiscal and royalty regime;
- supply projections to the year 2015, for synthetic crude oil and bitumen;
- the natural gas and electricity requirements directly related to oil sands operations;
- the existing pipeline network, future expansion, and capacity to move the expected incremental production to market;
- the market potential for the synthetic crude oil and bitumen in the domestic and export markets; and,
- the environmental impact of oil sands operations, steps being taken to reduce this impact and the organizations involved.

Supply costs for integrated surface-mining/upgrading projects have decreased from $30 to less than $13 per barrel (dollars of the day) in the last twenty years, due to continuous improvement in operations but also as a result of the development of innovative technologies. These innovations include the switch to truck and shovel operations from the dragline, bucketwheel and conveyor method, plus the development of the hydrotransport and low energy extraction systems.

The development of the steam assisted gravity drainage (SAGD) recovery method can be considered a major enabling technology. It has a number of advantages compared to previous steam stimulation methods that make it applicable to a wider range of bitumen reservoirs. Although not yet commercially proven on a large scale, industry confidence in this technology is illustrated by the fact that six commercial SAGD projects are currently planned to be in operation by 2005.

The supply costs for in situ projects have also been reduced through continuous improvement. Currently, most in situ operations utilize some form of cyclic steam stimulation (CSS) or SAGD recovery methods that use natural gas to provide heat for generating steam. The supply costs for these projects are highly dependent on the price of natural gas and the steam to oil ratio (SOR) or the amount of steam required per unit of production.

An analysis of the effect of higher gas prices on the economics of SAGD was undertaken for this report. For in situ bitumen the differential between the price of light versus heavy crude oil is also an important consideration, as is the cost and amount of natural gas condensate required for blending to meet pipeline specifications.

The supply projections use the the economic assumptions contained in the Board's Canadian Energy Supply and Demand Report to 2025 (Supply and Demand Report) including a US$18 (1997, real, constant) per barrel price for benchmark West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma. The assumption is made that the supply projections are unconstrained by markets or pipeline capacity. The projections include currently operating projects plus those project expansions or new projects already under construction, while other projects are ranked according to their relative merits. An industry cash-flow model is also used to assess the potential pace of production growth. Similar to the Supply and Demand Report, price sensitivities at US$14 and US$22 were included to gauge the relative response of production to price.

The review of pipelines describes current feeder and trunk lines as well as plans for new construction and expansion.

Due to declining conventional light and conventional heavy production in both Canada and the United States, and steadily rising demand for crude oil, a significant market opportunity is developing for synthetic crude oil and blended bitumen from Canada's oil sands. The review of markets examines the potential for the rising output of synthetic crude oil and blended bitumen to serve this market and also provides a discussion of the important factors determining whether the markets can absorb these volumes.

The discussion of environmental issues sets out the impact of oil sands activities on land, water, and air quality and also discusses the socio-economic impacts. In addition, it examines the programs and practices that are used to manage these impacts. As well, it describes various collaborative efforts on the part of industry, governments, local municipalities, aboriginal groups and environmental protection groups to improve environmental performance.

References

a) Alberta Energy and Utilities Board, *Alberta's Reserves 1999*, Volume 1, Statistical Series 2000-18.

b) National Task Force on Oil Sands Strategies, *The Oil Sands: A New Vision for Canada*, Alberta Chamber of Resources, 1995.

OIL SANDS RESOURCES

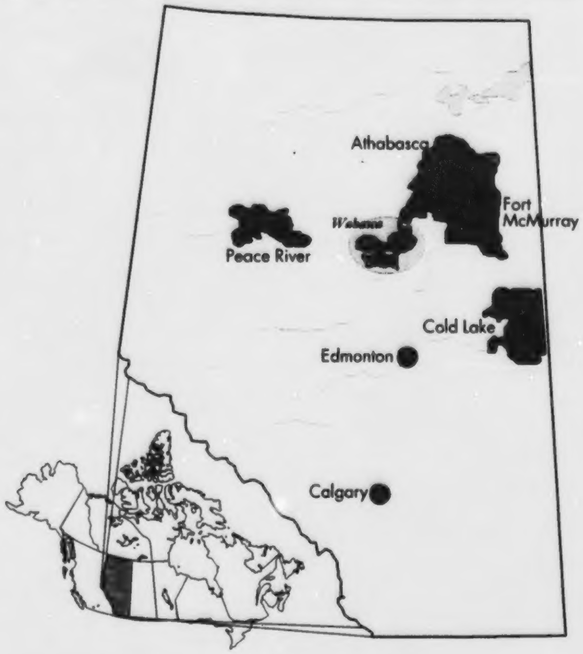
2.1 Introduction

This chapter presents a brief description of the location, magnitude, geological setting and characteristics of Canada's oil sands, including a discussion of crude bitumen characteristics.

2.2 Bitumen Resources

Canada's resources of crude bitumen occur entirely within the province of Alberta[1] and are found in sand and carbonate sedimentary formations in three regions defined as the Athabasca, Cold Lake and Peace River Oil Sands Areas (Figure 2.1). These areas cover a minimum of 4.3 million hectares, 729 thousand hectares and 976 thousand hectares respectively. The total area of the three regions is comparable in size to the province of New Brunswick, or to the countries of Scotland or Belgium.

FIGURE 2.1



The NEB adopts the crude bitumen resource estimates published by the Alberta Energy and Utilities Board (EUB).[a] The EUB estimates the initial volume in place of crude bitumen to be 259.2 billion cubic metres,[2] based on currently available data. The EUB further estimates the ultimate volume in place, a value representing the volume expected to ultimately be found by the time all exploratory and development activity has ceased, to be 400 billion cubic metres. Of this volume, 24 billon cubic metres are categorized as amenable to surface mining and 376 billion cubic metres available through in situ recovery or underground mining methods. The division between the surface mining and in situ areas is based on the thickness of the overburden, with thicknesses greater than 75 metres considered uneconomic for surface mining operations. Of the ultimate in-place volume, about 12 percent or some 49 billion cubic metres is estimated to be ultimately recoverable, including six billion cubic metres of bitumen contained in carbonate deposits that are considered to be beyond economic reach at the present time.

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[1] Minor oil sands deposits exist on Melville Island in Canada's Arctic Island Region.

[2] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

TABLE 2.1

Crude Bitumen Resources ($10^9 m^3$)

	Ultimate Volume In Place	Initial Volume in Place	Ultimate Recoverable Volume	Initial Established Reserves	Cumulative Production	Remaining Reserves
Mineable						
Athabasca	24	18	10	5.6	0.4	5.2
In Situ						
Athabasca	n/a	188.7	n/a	n/a	n/a	n/a
Cold Lake	n/a	31.9	n/a	n/a	n/a	n/a
Peace River	n/a	20.5	n/a	n/a	n/a	n/a
Subtotal	376	241.2	39	22.7	0.1	22.6
Total	**400**	**259. 2**	**49**	**28.3**	**0.5**	**27.8**

TABLE 2.2

Comparison of World Bitumen Resources ($10^9 m^3$)

Country	In Place Bitumen	Recoverable Bitumen
Canada	259.2	28.3
Former Soviet Union	186.1	60
Nigeria[1]	6.8	0.2
United States[2]	4.4	<.01
Venezuela[3]	8	n/a

1 Only includes volumes from the Ondo and Ogun States, with mineable portion only as recoverable.

2 Estimate only, small mining volumes for road material are considered recoverable at this time.

3 Does not include heavy or extra heavy crude oil. Source U.S. Geological Survey.

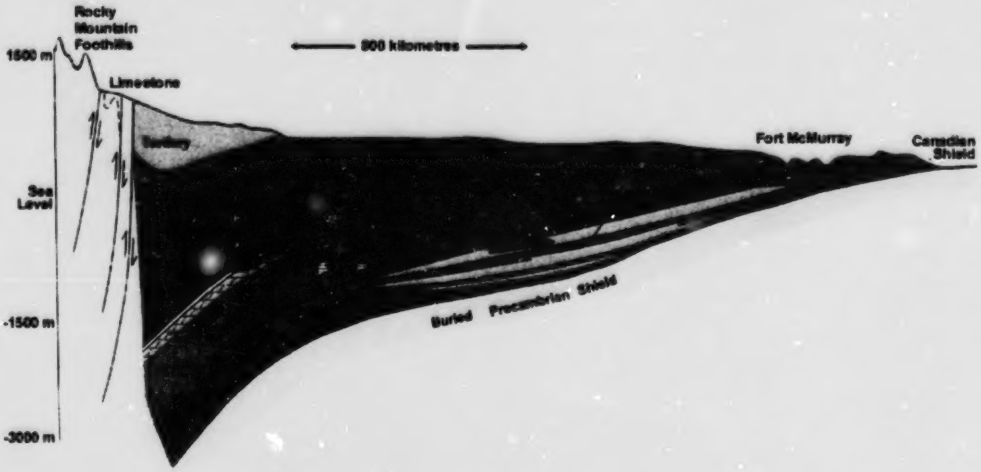
The estimation of the initial established reserves of crude bitumen takes into account current technology as well as current and anticipated economic conditions. It also involves the application of certain reduction factors that take into consideration items such as the required bitumen saturation and the degree of ore inaccessibility (Appendix A-1). Table 2.1 sets out the bitumen resources and reserves, ordered by recovery method, for each of the three regions.

Canada's oil sands are estimated to contain ultimate in-place bitumen resources of 400 billion cubic metres, making it the world's largest known concentration of bitumen. The current estimate of the ultimately recoverable volume represents only 12 percent of the ultimate volume of bitumen in place. There is considerable potential for this percentage to increase as advances are made in recovery technology. Although, by definition, proven reserves are not directly comparable to ultimate recoverable resources, it is interesting to note that the proven reserves of Saudi Arabia, all classified as conventional crude oil, at about 43 billion cubic metres, are roughly comparable to Canada's recoverable bitumen resources.

Canada's oil sands deposits easily rank as the largest of their kind in the world (Table 2.2). The initial established reserves, estimated to be 28.3 billion cubic metres, would be sufficient to satisfy domestic demand for nearly 100 years.

FIGURE 2.2

Oil Migration Path



2.3 Oil Genesis, Migration And Biodegradation

The age of the source rocks for the oil found in the Alberta oils sands deposits is still a matter of some uncertainty. The uncertainty centres on whether the source rocks are Mississippian or Jurassic age, or some combination of the two. This much is clear: light oil was sourced in the deeper portions of the Western Canada Sedimentary Basin (WCSB) in pre-Cretaceous formations and migrated long distances to the present location of the deposits (Figure 2.2). The McMurray or equivalent sands were the primary collectors of the generated oil and provided the main conduit for migration. It is speculated that the migration path was at least 360 kilometres for the Athabasca Deposit and at least 80 kilometres for the Peace River deposits. These lighter oils were then subjected to biodegradation transforming them into bitumen.

Biodegradation occurred where microbes, carried in by oxygenated water, acted on the trapped oil. This microbial action preferentially decomposed the lighter hydrocarbon molecules, leaving the more complex heavy molecules, heavy minerals and sulphur behind. As a result, the specific gravity and sulphur content of the crude oil increases. As well, the concentration of heavy minerals such as vanadium, nickel, magnetite, gold and silver also increases. It has been estimated that prior to biodegradation, the original volume of oil in the oil sands was two to three times as large as it is today. The characteristics of the bitumen and the reservoir properties of the oil sands are in large part a function of the degree of biodegradation that took place.

2.4 Oil Sands And Bitumen Characteristics

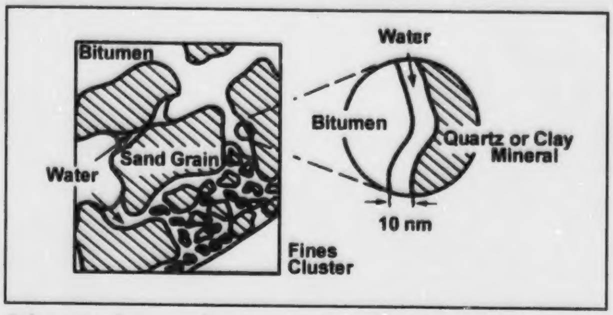
The oil sands deposits are composed primarily of quartz sand, silt and clay, water and bitumen, along with minor amounts of other minerals, including titanium, zirconium, tourmaline and pyrite. Although there can be considerable variation, a typical composition would be:

- 75 to 80 percent inorganic material, with this inorganic portion composed 90 percent of quartz sand;
- 3 to 5 percent water; and,

- 10 to 12 percent bitumen, with bitumen saturation varying between zero and 18 percent by weight.

The oil sands are generally unconsolidated, and therefore quite friable and crumble easily in the hand.

FIGURE 2.3



Schematic diagram showing a structural model of Athabasca oil sand. The water in the oil sand appears in three forms: as pendular rings at grain-to-grain contact points, as a ~ 10 nm thick film which covers the sand surfaces, and as water retained in fines clusters. The remaining void is occupied by bitumen. Courtesy of AOSTRA.[b]

A key aspect of the oil sand reservoirs is the presence of bound formation water, which surrounds the individual sand grains as a layer (Figure 2.3). The bitumen is trapped within the pore space of the rock itself. This is similar to most conventional oil reservoirs, and the reservoir rock is said to be "water-wet", that is, each sand grain is surrounded by an envelope or film of water about 10 nanometres thick. The presence of the water layer around the grains enables the bitumen to be recovered more easily since the bonding forces between the bitumen and water are much weaker than those between the water and the sand grains.

The bitumen contained in the oil sands is characterized by high densities, very high viscosities, high metal concentrations and a high ratio of carbon to hydrogen molecules in comparison to conventional crude oils (Table 2.3). With a density range of 970 to 1 015 kilograms per cubic metre (8-14°API), and a viscosity at room temperature typically greater than 50 000 centipoise, bitumen is a thick, black, tar-like substance that pours extremely slowly. The average composition of Alberta's bitumen is 83.2 percent carbon, 10.4 percent hydrogen, 0.94 percent oxygen, 0.36 percent nitrogen and 4.8 percent sulphur, along with trace amounts of heavy metals such as vanadium, nickel and iron.[c]

All crude oils contain a complex mixture of hydrocarbons - chains of carbon and hydrogen atoms. Chains of less than 4 carbon atoms are gaseous in their natural states, while longer chain lengths exist as liquids or solids. Average crude oils contain about 84 percent (by weight) carbon, 14 percent hydrogen, 1 to 3 percent sulphur and minor amounts of nitrogen, oxygen, metals and salts. If the crude oil contains hydrogen sulphide or reactive sulphur compounds, it is termed to be sour. Crude oils are classified as paraffinic, naphthenic, or aromatic depending on which of these hydrocarbon molecular structures is predominate. Crude oils are defined in terms of the density or specific gravity. Light oils have a low specific gravity while heavy oils have a high specific gravity. When the API gravity terminology is used, the scale is reversed such that the higher the API gravity, the lighter the oil. Another property used to classify crude oils is viscosity, which is a measure of the ability to flow. Low viscosity oils flow freely, while high viscosity oils resist flow.

Bitumen is deficient in hydrogen, compared to typical crude oils which contain approximately 14 percent hydrogen. Therefore, to make it an acceptable feedstock for conventional refineries, it must be upgraded through the addition of hydrogen or the rejection of carbon. In order to transport bitumen to refineries equipped to process it, bitumen must first be blended with a diluent, commonly referred to as condensate, to meet pipeline specifications for density and viscosity.

2.5 Reservoir Characteristics

Alberta's oil sand deposits have been grouped on the basis of geology, geography and bitumen content and have been defined as the Peace River, Athabasca and Cold Lake

- 10 to 12 percent bitumen, with bitumen saturation varying between zero and 18 percent by weight.

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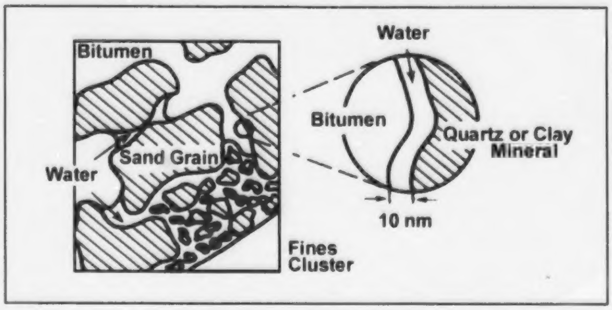

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Oil Sands Areas. The previously defined Wabasca Area has been reclassified by the EUB and is now included as part of the Athabasca Oil Sands Area.

TABLE 2.3

Comparison of Crude Oil Characteristics

Crude Oil Sample	Crude Type	Location	Density (kg/m^3)	API Gravity (degrees)	Viscosity (cp @ 24°C)
Cardium	light	Alberta	834	33	~4
Hibernia	light	Newfoundland	828 - 896	30 - 40	~10
Sparky	heavy	Alberta	959	14	2 600 - 8 900
Kern River	heavy	California	964	13	2 985
Athabasca	bitumen	Alberta	970	11.6	17 000 - 265 000
Peace River	bitumen	Alberta	1 040	5.6	125 000 - 155 000

The characteristics of the bitumen and the reservoir properties of the oil sands is in large part a function of the degree of biodegradation that took place. For the Peace River deposits, the oil migrated the shortest distance and was subjected to only a moderate degree of biodegradation, while for the Athabasca and the Cold Lake deposits, the migration distance was considerably farther and therefore these deposits were subjected to a greater degree of biodegradation. Some of the distinguishing characteristics of the three areas are:

- the Peace River deposits contain bitumen in Mississippian carbonates, as well as in the Permian and Cretaceous sandstones;
- the Athabasca deposit has the largest areal extent and contains bitumen in the Devonian carbonates and the Cretaceous sandstones; and,
- the Cold Lake deposits contain bitumen only in the Cretaceous sandstones.

Table 2.4 summarizes some of the more important characteristics for reservoirs within each of the oil sands formation types.

2.6 Geology Of The Alberta Oil Sands Regions

2.6.1 Stratigraphy

The oil sands regions of northeastern Alberta have the thinnest portion of sedimentary cover in Alberta. Between Fort McMurray and Lake Athabasca, the sedimentary section is completely eroded

TABLE 2.4

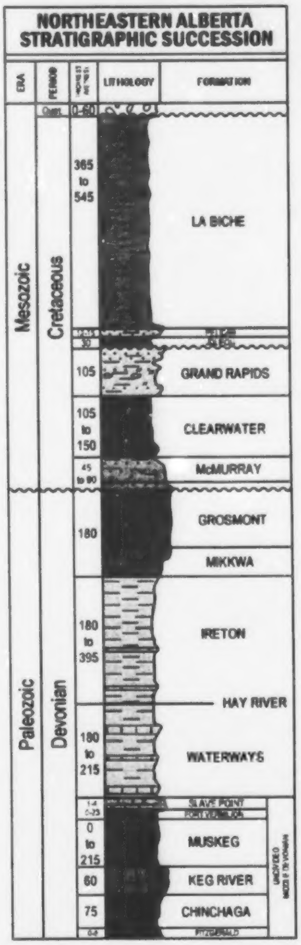
Reservoir Characteristics

	Area [1] (hectares)	Net Pay (metres)	Porosity (percent)	Water Saturation (percent)	Bitumen Saturation (percent)	Percent Bitumen by Weight	API Gravity (degrees)
Carbonate Deposits	26 000 - 1 190 000	5 - 29	14 - 27	25 - 48	52 - 75	3.5 - 8.0	8 - 23
McMurray Oil Sands	20 - 4 239 000	0.5 - 50	25 - 31	14 - 49	51 - 86	6 - 13	6 - 13
Grand Rapids Oil Sands	20 - 334 000	0.2 - 10	23 - 37	14 - 55	45 - 86	5 - 15	10 - 12

[1] The deposits are divided into stratigraphic zones and pools, each with its own assigned area.

and the granitic rocks of the Precambrian Shield are exposed at the surface. The thickness of sediments increase rapidly to the west and southwest.

FIGURE 2.4


NORTHEASTERN ALBERTA STRATIGRAPHIC SUCCESSION

The lowermost sediments consist of Middle Devonian Elk Point Group which may reach a thickness of 350 metres. The Elk Point Group is made up of Ernestina Lake evaporites, Chinchaga red beds and evaporites, Keg River dolomites and limestones, and Muskeg evaporites. The Elk Point is capped by Upper Devonian deposits which may attain a thickness of 720 metres. The Upper Devonian consists of Slave Point/Fort Vermillion carbonates and marine shales of the Waterways and Ireton Formations, capped by dolomitic limestones of the Grosmont Formation. The Waterways and Ireton Formations are important source rocks for Devonian pools elsewhere in the province.

The Devonian section is capped by the much younger Cretaceous section which can attain a thickness of 925 metres in the region. The lowermost Cretaceous deposits consist of McMurray Formation sandstones, capped by interbedded sands and shales of the Clearwater/ Grand Rapids/ Joli Fou/ Pelican Formations. The youngest Cretaceous section consists of shales of the La Biche Formation. The Cretaceous section is capped by variable thicknesses of recent glacial gravels, sands and clay deposits.

2.6.2 Structure

The Precambrian erosional surface dips to the southwest at a rate of 4.5 metres per kilometre in this region of Alberta. On that erosional surface, there is a basement anticlinal feature trending north-south which extends through the oil sands region. As well, outside of the northeastern region, there are large structural arches which interrupt this surface. In addition, there are several basement shear zones which trend in a northeast-southwest direction. These may be important in the migration process. The Devonian section generally follows the same regional structural trend as the erosional surface. Salt tectonics within the Devonian section emphasize the basement anticlinal feature on the east side. This occurred where the salts were exposed to surface erosion and were removed preferentially. The Devonian section capping the Elk Point salts have collapsed along the subcrop edge leaving a carbonate breccia deposit.

The Cretaceous section is relatively flat lying in northeastern Alberta. The thickening Devonian section fills the space between the flat Cretaceous and the deepening Precambrian erosional surface. Other carbonate reservoirs are added to the section in the more western portions of the region including the Nisku Formation. Further westward, the Mississippian and Triassic sections are added. On the eastern side, over the edge of the salt collapse zone, anticlinal traps may develop within the Cretaceous section. The anticlinal development forms the structural component of the trapping mechanism that keeps the oil in the McMurray Formation. Locally, natural gas may be trapped in the upper portions of the McMurray Formation.

2.6.3 Reservoir Descriptions

In the westernmost part of the Athabasca deposits, the Devonian Nisku and Grosmont carbonates also contain bitumen deposits, but these are too deep for surface mining techniques. The Nisku consists of thick dolomitized fossiliferous carbonates. The Grosmont consists of a series of shallowing upwards depositional cycles with good horizontal continuity but less vertical continuity. Deposits range from deep water types to shallow water tidal deposits.

In the Peace River Oil Sands Deposit, the carbonate reservoirs are found in the Mississippian Shunda Formation, while sandstone reservoirs are found in the Permian Belloy Formation and the Cretaceous Bluesky-Gething Formations, which are equivalent in age to the McMurray Formation. These sandstones occupy the Peace River Channel, which drained to the northwest, and was a tributary to the Spirit River Channel found further west. The oil sands deposits are at the updip edge of the Peace system.

The Lower Cretaceous McMurray sandstones are the main host rocks for the bitumen deposits of the Athabasca oil sands. The McMurray sands are composed of an interbedded sequence of sandstones, siltstones, mudstone and coals. Overall, grainsize decreases from bottom to top. The McMurray sands can be sub-divided into three sub-units: a dark mudstone with minor amounts of coal, a clean sandstone unit, and a sequence of fine sandstone and siltstone. The mudstone unit is found locally at the Cretaceous-Devonian boundary and may reflect older units eroded before Cretaceous deposition occurred. The sandstone unit ranges in grain size from very coarse to very fine, and reflects fluvial deposits of both meandering and braided stream types. The sand/silt unit is characteristic of deposition at the junction of river and marine deposits where tidal influences are readily apparent. The rivers associated with both of these sub-units were north flowing as part of the St. Paul Channel system, which drained eastern Alberta and western Saskatchewan. The upper unit was deposited as the Boreal Sea transgressed from north to south. The overlying Clearwater Formation consists of a silty mudstone which acts as a seal to stratigraphically trap the oil within the McMurray Formation.

The overlying Grand Rapids Formation is primarily a siltstone deposit, but does contain a number of thick channel sand deposits at a variety of stratigraphic levels. The Grand Rapids Formation deposition is indicative of an oscillating shoreline, marked by alternating sand and shale deposition corresponding to the northward retreat or southward advance of the Boreal Sea. Further westward in the Athabasca deposits, these channel deposits contain significant amounts of bitumen.

2.7 Conclusion

The magnitude of Canada's bitumen resources, contained in the three Alberta Oil Sands Areas, is immense. Based on current technology, about 12 percent, or 49 billion cubic metres is estimated to be ultimately recoverable.

The accepted theory for the formation of the oil sands is that oil in Missippian and Jurassic age sediments to the southeast migrated to the present day oil sands areas. Subsequent biodegradation transformed the light oil into a black, tar-like material known as bitumen.

Bitumen is heavy, viscous, and hydrogen deficient compared to conventional crude oils, and is therefore problematic for conventional refineries. It has to be upgraded locally, or transported to market after blending with a condensate.

Oil sands deposits deeper than about 75 metres are considered too deep to be surface mined economically. Therefore, only 20 percent of the ultimately recoverable volume is considered amenable to surface mining, while the remaining 80 percent will require some form of in situ recovery.

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CHAPTER THREE

OIL SANDS PIONEERS

3.1 Introduction

The early history of the oil sands is replete with accounts of individuals of courage and conviction who persevered, often in the face of incredible hardship and disappointment, to pursue their vision for oil sands development. Among these, two men stood out — Sidney Ells and Karl Clark. In this chapter, some of the more noteworthy people and events are highlighted.

The story of the oil sands pioneers is truly a fascinating one, and readers are encouraged to seek out some of the accounts of the history of oil sands development.

3.2 Early Days

The first recorded mention of the Athabasca oil sands is attributed to the English explorer Henry Kelsey. In 1719, while serving as manager of the Hudson's Bay Company trading post at York Factory, Kelsey noted in his journal that a Cree aboriginal named Wa-Pa-Su had given him a sample *"of that Gum or pitch that flows out of the Banks of the River."*[a]

The North West Company fur trader and explorer Peter Pond is considered to be the first European to reach the Athabasca region, in 1778. His notes contain reference to the oil sands, as do those of explorer Alexander Mackenzie, who passed through the region in 1789.

Sir John Richardson visited the region in 1819 as part of Sir John Franklin's quest to find the "Northwest Passage", a shorter route to the Pacific Ocean via Canada's northland, and returned in 1848 when searching for Franklin's lost third expedition. Richardson had a knowledge of geology, and provided the first real scientifically based account of the Athabasca oil sands deposits. He correctly determined that the oil sands were continuous throughout the region and overlie much older Devonian limestones.

John Macoun was a botanist assigned to a Geological Survey of Canada (GSC) team with the responsibility for finding routes for railway construction through the Rocky Mountains. On a return trip from British Columbia he made his way down the Peace and Athabasca Rivers. It was his detailed account of the oil sands outcroppings and the nature of the bitumen he found there that led to further investigation by the GSC. Macoun foresaw a time *"when man would be busy, with his ready instrument, steam, raising the untold wealth which lies buried beneath the surface, and converting the present desolation into a bustling mart of trade"*.[b]

The GSC initially concentrated its exploration south of Fort McMurray near Athabasca Landing. Their investigations, led by Dr. Robert Bell, Dr. R.G. McConnell and Dr. George M. Dawson, were based on the premise that there was a large pool of "pure petroleum" or "free oil" beneath the oil sands, trapped by the shale formations they knew existed in the region. A well was drilled at Athabasca Landing, to a depth of nearly 600 metres, but no oil pool was found. The drilling equipment was moved to Pelican Rapids where a well was drilled in 1896. No oil was found, but the well resulted in an uncapped gas well that blew gas for twenty years before it was finally capped in 1918.

In the late 1890s, Dr. Christian Hoffman of the GSC experimented with hot water treatment of the oil sands in his Ottawa laboratory, and was able to separate bitumen from the sand grains.

Alfred Von Hammerstein was a German count who was lured to North America to join the Klondike Gold Rush. He passed through the Athabasca region on his way to the Yukon and later returned to settle near Athabasca Landing. He became increasingly interested in the oil sands and undertook to drill a number of wells just south of Fort McMurray. Von Hammerstein, like the GSC geologists before him, was looking for a pool of "free oil" that he thought fed the oil sands. He drilled eight wells in the area without success, but his investigations did further the cause of development of the region. On his own initiative, he travelled to Ottawa to deliver a report to a Senate Committee of the federal government. He presented a glowing, if somewhat exaggerated, account of the mineral wealth of the Athabasca region, including oil sands, coal, salt, copper, limestone and gold. A central theme of Von Hammerstein's report was the usefulness of the oil sands bitumen to produce asphalt.

3.3 Sidney C. Ells

FIGURE 3.1

S.C. Ells (Northland Trails by S.C. Ells, Burns and MacEachern, Toronto, 1956)

The following statement was made in 1950 by Max Ball, a long time friend and associate of Ells. "S.C. Ells may well be called the father of the Alberta bituminous sand research and development. He made the first systematic study of the deposits and the first — and as yet the only — comprehensive maps of the area in which they lie. He made the first systematic study of methods for separating the bitumen from the sands. He first developed and demonstrated the principal of hot water separation through pulping the bituminous sands and recovering the separated bitumen in a flotation cell. For thirty-five years, in the face of indifference and skepticism, he has been the courageous and unremitting advocate of the value and importance of the bituminous sand deposits".[5]

The federal government's involvement with the Athabasca oil sands was renewed in 1913. In a letter to the government in Ottawa, an Alberta MLA, Jean L. Côté, asked about its plans for the development of the northern Alberta oil potential. In attempting to answer his queries, the federal Department of Mines realized the lack of detailed information there was on the Athabasca deposits. The team from the Mines Branch that was formed to conduct further investigation included Dr. Sidney C. Ells, a young engineer.

Over the next forty years, Ells was one of the major driving forces leading the efforts to characterise and develop the oil sands.

Ells' report at the end of the 1913 field season concluded that there was no pool of "free oil" below the oil sands, rather, the oil was dispersed throughout a particular sand layer. He also concluded that the sand held immense quantities of bitumen that could not be recovered by traditional drilling and pumping methods. Ells, who had some background in evaluating materials for road construction, also urged that the oil sands bitumen be utilized as a source of asphalt. In addition, he recommended that techniques be developed to separate the oil from the sand. On his advice, the National Parks Branch created the Horse River Reserve, setting aside 232 hectares of land just south of Fort McMurray for the purposes of oil sands research.

Early attempts to demonstrate the possible commercial use of the oil sands as a paving material included:

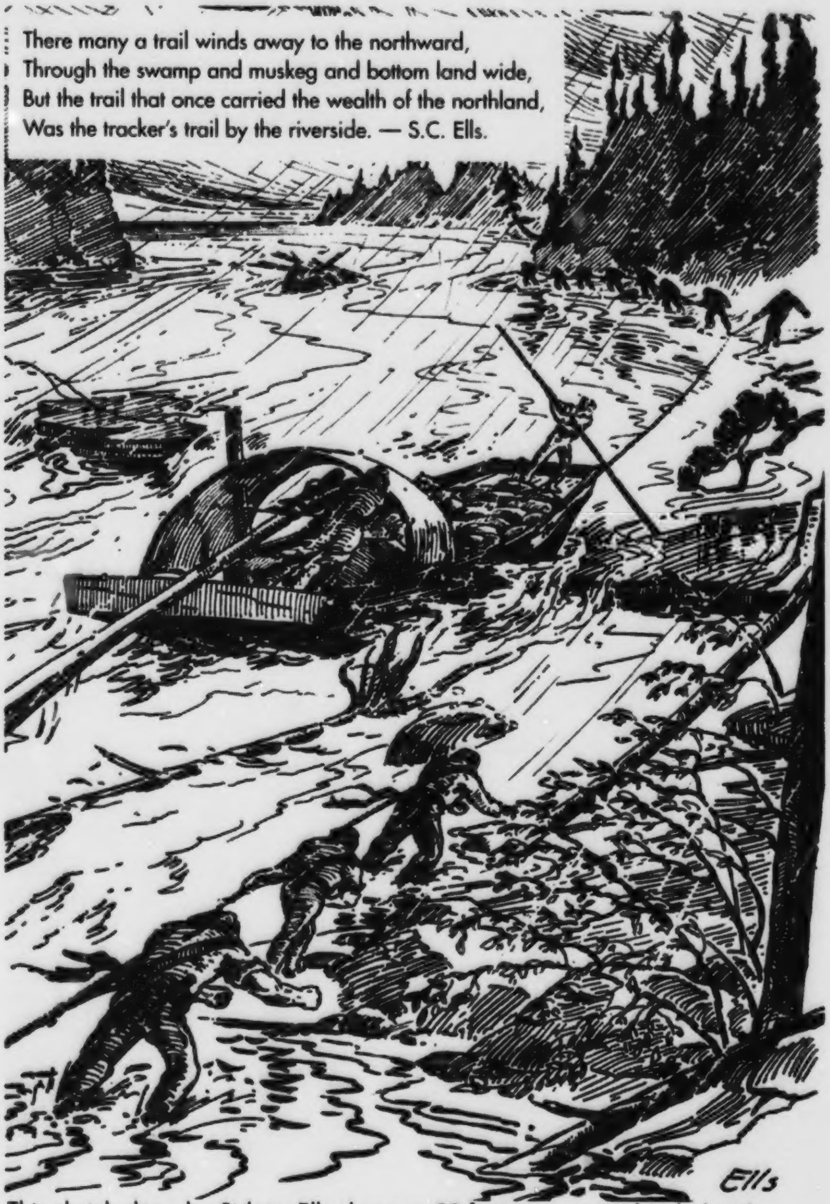
- a 60 square metre section of demonstration pavement at Kinnaird Street in Edmonton, that was laid in 1915 and was in service until the 1950s;
- paving trials on Wellington Street and Parliament Hill in Ottawa, Ontario;
- a Parks Branch plan to use oil sands to pave the streets of Jasper that was completed in 1927;
- a bridge paving project in Medicine Hat in 1935, by D. M. Draper of Fort McMurray; and
- the paving of 22 blocks of sidewalk in Camrose, Alberta.

Although the oil sand performed well in paving applications, as sheet pavement or when mixed with other aggregates, the high cost of transporting the material from the north made the economics marginal. As well, developers began to realize that oil sands would have far greater potential value as a source of transportation fuels, and interest in using oil sands as paving material waned.

The completion of the Northern Alberta Railway line to the Fort McMurray area in 1920s made it much easier to move people and equipment into the region, and the stories of the potential wealth of the oil sands attracted many inventors and promoters. Ells believed that the oil sands entrepreneurs were necessary to develop the resource and on his recommendation the federal government adopted a policy of supporting private sector investment in the oil sands. He also urged the federal government to invest. In 1925, the Canadian government initiated a core-drilling program, designed to recover samples, that would be subsequently shipped to Mines Branch laboratories in Ottawa for further analysis. In 1926, Ells listed 41 wells drilled in the area, mostly within the Horse River Reserve, including two by the Alberta government.

Ells was aware that hot water separation techniques had been tried in Europe and in the United States where deposits of oil sands also occur. In 1913, after visiting several sites in the United States, he determined that a separation plant located in Carpinteria, California had processed a material similar to the Athabasca oil sands and held the most promise. In 1915, Ells was invited to conduct his research on hot water separation at the Mellon Institute of Industrial Research in Pittsburgh, Pennsylvania. At Mellon, Ells experimented with his separation process by varying temperatures and pressures and testing the effects of various acids and alkalis. Based on the success of his experiments, Ells was assured that the hot water separation process could be successfully applied to the Athabasca oil sands.

At this point in his career he turned his attention once again to the characterisation of the oil sands deposits and the promotion of oil sands development. In 1930, the provinces were given full control over natural resources, but the federal government did retain several leases around Fort McMurray. Ells continued to promote research and development in the area and his efforts led to renewed exploratory work by the GSC in the 1940s and early 1950s. After his retirement in 1954, Ells devoted his time to writing and sketching. He was able to attend the First Oil Sands Symposium in Edmonton in 1951 and was present at the Great Canadian Oil Sands opening ceremonies in 1967. Sidney Ells died in Victoria in 1975.



There many a trail winds away to the northward,
Through the swamp and muskeg and bottom land wide,
But the trail that once carried the wealth of the northland,
Was the tracker's trail by the riverside. — S.C. Ells.

This sketch done by Sidney Ells shows a 50-foot river scow, loaded with sacks of oil sand, being pulled upstream on the Athabasca River by a team of "trackers". This arduous form of labour was a common means of transporting goods south from Fort McMurray to Athabasca Landing, a distance of 280 kilometres, until the railway was completed to the Fort McMurray area in the 1920s.

Chronology

1719	Sample of bituminous sands brought to York Factory by Wa-pa-su, 'the Swan', a Cree Aboriginal from the Athabasca Country.
1778	Peter Pond is the first white man to enter the Athabasca Country, crossing the Methye Portage to the Clearwater River, and continuing down the Athabasca to build a fort at a point some thirty miles from the mouth of the river. Describes seeing the oil sands.
1791	Peter Fidler, Surveyor for the Hudson's Bay Company (HBC) records seeing the oil sands.
1792	Alexander Mackenzie travels the same route to the Athabasca country as did Pond, and reports seeing the oil sands.
1820	John Richardson gives earliest geological interpretation of the oil sands deposits.
1848	On a searching expedition seeking the fate of Franklin, Richardson adds to his knowledge of the oil sands.
1870	Henry John Moberly, HBC factor builds a trading post at the forks of the Clearwater and the Athabasca, naming it Fort McMurray for the HBC inspector who sent him to build the post.
1875	John Macoun, Botanist with a Dominion Government group investigating the West describes the oil sands.
1878	In his annual report, G.M. Dawson, Director of the GSC makes the first technical reference to the oil sands.
1882	Dr. Robert Bell of the GSC describes gas bubbles in river and explains geological sequence.
1883	First attempt at laboratory separation of oil from sand, in Ottawa by Dr. G.C. Hoffman.
1893	Dr. R. D. McConnell, GSC, makes more detailed structural observations.
1894	Government well sunk at Athabasca Landing by Dr. McConnell. Well abandoned in 1895.
1896	Government well sunk at Pelican Rapids, encountered natural gas flow which blew for 20 years.
1897	Klondike Gold Rush brings many people through the Athabasca region.
1906	A. Von Hammerstein drills a well on the Athabasca River.
1907	A. Von Hammerstein describes the Athabasca region to a senate investigating committee, with emphasis on the oil sands deposits.
1909	Von Hammerstein encounters brine in his well. Interest in salt mining.
1911	Gold encountered in drilling.
1913	Ottawa sends Sidney Ells to investigate extent and use of oil sands.
1914	Shift in thinking of oil sands: suggestion that material found may be as valuable as oil field sought beneath.
1915	First pavement laid using Athabasca oil sands - in Edmonton, Alberta.
1917	Dr. F.H. McLearn (GSC) names oil sand strata Fort McMurray Formation
1918	Northwest Company Ltd. (a subsidiary of Imperial Oil Co. Ltd.) drilled in Tp 85.
1920	Ottawa stops leasing land in Athabasca region.
1921	The Alcan Oil Company, formed of New York City Policemen drilled for oil in township 96.
1925	Dominion Government begins to take core samples of oil sand. Dr. Clark studies area for Alberta.
	J.O. Absher forms the Bituminous Sand Extraction Company and begins in situ experiments.
1926	Railway completed to Fort McMurray.
1927	International Bitumen Company formed by R.C. Fitzsimmons.
1930	Abasand Oils begins operation under Max Ball's direction.
	All Canadian natural resources are brought under provincial jurisdiction. R.C. Fitzsimmons makes first shipment of commercially saleable bitumen, to Edmonton.
1943	Oil Sands Limited takes control of Fitzsimmons' plant at Bitumount.
1947	Discovery of huge conventional crude oil reservoir at Leduc, Alberta.
1948	Dr. D.S. Montgomery joins Federal Bureau of Mines. Begins work on chemical structure of bitumen.
1949	Province of Alberta takes over Bitumount site as Oil Sands Project.
1951	Province of Alberta holds first Athabasca Oil Sands Conference.
1953	Sun Oil Company, led by J. Howard Pew, forms Great Canadian Oil Sands Company to pursue oil sands development.
1955	Bitumount area taken over by Can-Amera Company.
1958	First plan to separate sands with nuclear explosion proposed.
1958	New flurry of interest in 1911 gold.
1962	Great Canadian Oil Sands granted first production permit in oil sands by Alberta government.
1963	Sun Oil Company decided to back separation plant for Great Canadian Oil Sands Company.
1967	Great Canadian Oil Sands plant begins production of crude oil.
1974	Province of Alberta grants second production permit to Syncrude, a consortium of oil companies.

3.4 Dr. Karl A. Clark

FIGURE 3.2

Karl A. Clark, 1918. (CFC)

The simple term "Oil Sands Scientist" perhaps best describes Karl Clark. In 1920, President Tory of the University of Alberta gave him the task "to find a way of bringing the Athabasca tar sands into utilization." Through a lifetime of dedication and disciplined research he was able to fulfill this commitment. He is widely recognized as the developer of the hot water bitumen extraction process which formed the basis of the process utilized by the two large mining/upgrading plants in operation at Fort McMurray.

After receiving his doctorate in Physical Chemistry from the University of Illinois in 1916, Karl Clark's first assignment was with the Geological Survey of Canada. Due to a reorganization in his department, he was transferred to the Road Material Division of the Mines Branch, in Ottawa, where he was asked to organize and critique the reports of Sidney Ells. Through this work, he developed a good understanding of the Athabasca oil sands.

During a visit to Manitoba in the summer of 1918, Clark noted that the clay soils of the prairies make the roads almost impassable in wet weather. Clark thought that the Athabasca tar sands might be used to waterproof these roads.[4]

In 1920, he received samples of the oil sands to study and, in the course of his work, developed a method of separating the oil from the sand using a chemical additive.

At this time, the University of Alberta decided to set up and finance its own facilities to conduct oil sands research. Clark was recruited to the post of research professor in the newly formed Scientific and Industrial Research Council of Alberta, which later became the Alberta Research Council.

By the fall of 1922, Clark had concluded that the use of Athabasca oil sands for paving purposes was not economically viable, and he turned his attention to developing his oil sands separation techniques. Clark developed a method by which a froth of oil was formed by introducing additional hot water into the original mixture of oil sands pulp and hot water. The froth, containing the oil, could be skimmed off the surface, while the sand grains sank to the bottom of the container.

Sydney M. Blair, a young engineer, joined Clark as his assistant in 1922. They set about designing and building the first oil sands separation plant capable of batch operation. This apparatus, located in the basement of the University of Alberta's power plant building, worked very well and led to the construction of a larger plant located on the outskirts of Edmonton at the Dunvegan Yards. The Dunvegan plant of 1925 was the first continuous separation plant for oil sands ever built and operated. Clark and Blair also spent time in the fields surveying and sampling the deposits along the Athabasca River. In 1926 they released a major report on their work entitled "The Bituminous Sands of Alberta."

In 1929, the Alberta Government and the Alberta Research Council asked Dr. Clark to identify a site suitable for a mining plant and to build a pilot plant beside a quarry. The Dunvegan plant was modified, tested, dismantled and shipped by train and barge to a site on the Clearwater River. The Clearwater plant was in operation throughout the summer of 1930 and produced 60 000 litres of oil. Clark was pleased with the plant performance and reported that 90 percent of the oil in the sand was being recovered and that the mineral content of the froth was down to 4.9 percent, both better than laboratory studies had indicated.[e]

Dr. D. S. Pasternack, who had just finished his doctorate in organic chemistry at McGill University, was hired to assist Clark with the problem of dehydrating the wet oil produced by the plant, which contained entrained water of about 30 percent. The answer they found was to mix the bitumen with salt in a steam-jacketed mixing and kneading machine, with the temperature precisely controlled. Using this method, they were able to reduce the total water and mineral content to less than two percent.[f]

As a result of the cost cutting made necessary by the Depression, the Research Council of Alberta was disbanded in 1933, and Dr. Clark's focus turned more to soil surveys and soil classification.

World War II brought a renewed interest in petroleum resources and the Research Council was reinstated in 1942.

In 1944, Clark determined that oil sand in its natural state was "water-wet", that is, each sand particle is separated from the oil by an envelope of water. He also established that this condition was necessary for separation of the oil from the sand to occur. In addition, he established that the fine clays had to be present in the proper concentration to achieve effective separation results.

After 1945, Clark served as advisor to a group building a pilot plant at Bitumount and also advised in its subsequent operation.

Clark remained at the University of Alberta until his retirement in 1954, but continued on with the Alberta Research Council until 1963. During this time, his advice was widely sought by researchers and industry personnel alike. Dr. Karl A. Clark passed away in December 1966.

3.5 Early Projects

3.5.1 Bitumount

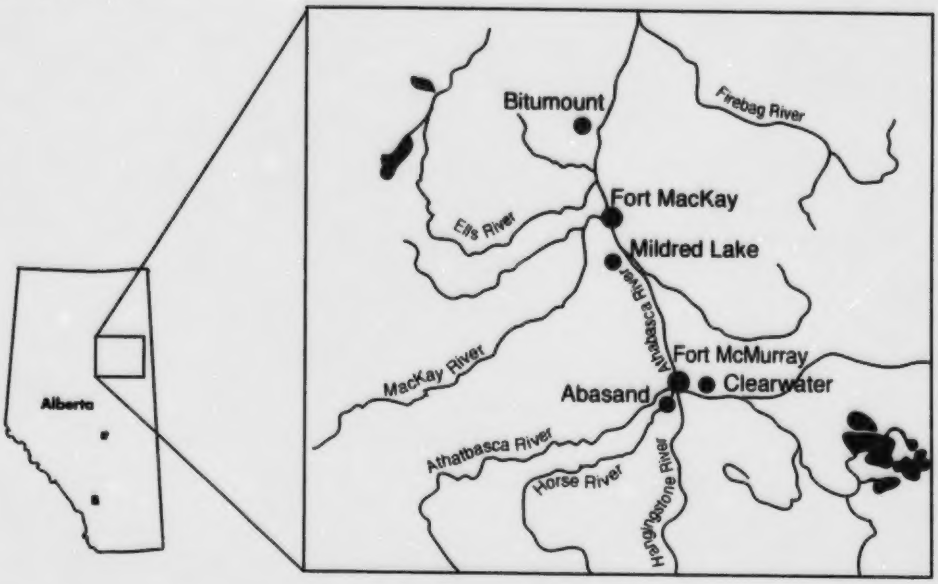
Encouraged by a favourable leasing policy on the part of the federal government, many people came to the Athabasca region to make their fortune in the oil sands.

In 1922, a group of New York City policemen formed the Alcan Oil Company and acquired a lease north of Fort McMurray on the east side of the Athabasca River. Their plan was to inject hot water down a well to heat the oil sands from which bitumen would then be extracted. Unfortunately, their plan failed and they sold their rights to Robert Fitzsimmons in 1923.

Fitzsimmons turned his attention to mining and extraction rather than pursuing down hole recovery. In the course of his experiments, he constructed a small extraction plant based on hot water separation. This plant became the first field plant to extract oil from the Athabasca oil sands. At this site, which came to be known as Bitumount, Fitzsimmons established the International Bitumen Company in 1927 (Figure 3.3). Over the following years, he continued to perfect his process. In 1938, the plant produced 400 cubic metres of specification asphalt and 320 cubic metres of fuel oil.[g]

FIGURE 3.3

Early Projects



Fitzsimmons' operation faced increasing financial difficulties, and he lost control of the plant in 1942. The Alberta government operated it as an experimental facility for several years before it was shut down in 1949.

3.5.2 Abasand

Abasand Oils Limited was formed in 1931, by an American named Max Ball, on a lease in the Horse River Reserve. Abasand had an agreement with the federal and provincial governments to have an operational plant in place by 1936 that could process 250 tons of oil sands per day.

The plant was completed on schedule and was close to being commercially successful when it was completely destroyed by fire in 1941. Ball rebuilt the plant but it did not regain the level of success it had before the fire and he decided to abandon the operation in 1942.

The federal government, concerned about securing adequate supplies of crude oil for the war effort, had renewed interest in the potential of the Athabasca oil sands. They took over the Abasand plant in 1943, but were never able to achieve any degree of success. In 1945, fire again completely destroyed the plant, marking the end for Abasand.

In 1947, a huge conventional light crude oil reservoir was discovered at Leduc, Alberta, with the discovery of other large pools following close behind. This deflected interest away from the oil sands, but the infrastructure put in place to exploit these conventional resources would later enable oil sands development.

3.5.3 Blair Report

The Blair report, which was released in 1950, was prepared for the Alberta government by S.M. Blair and E. Nelson, and indicated that oil sand development would be economically feasible if done on a scale of 3 200 cubic metres per day or greater. This report, along with an oil sands symposium that was held in Edmonton in 1951, sparked renewed industry interest. A dozen oil companies pursued exploration targets of 20 230 hectares each, to be explored over the following three years.

The regulations allowed companies to acquire leases if they found something of interest, but the leases carried a requirement to begin building a commercial plant within one year of obtaining the lease. Few companies were willing to take this risk, so the province changed the rules such that a lease holder was only required to proceed with a commercial plant within one year if instructed to do so by the government. This change in regulation encouraged many companies to acquire oil sands leases and helped set the stage for the first commercial projects.

3.5.4 First Commercial Mining Projects

Under the leadership of J. Howard Pew, Sun Oil Company did extensive investigation of their oil sands leases, beginning in the early 1950s, and undertook to build the first surface mining and upgrading plant. The Great Canadian Oil Sands (GCOS), now Suncor, operation began in 1967. The lessons learned from its construction and from solving early operational problems paved the way for the modern oil sand industry.

The Syncrude project, a consortium of companies that had been actively involved in oil sands exploration for a number of years, including involvement in the Abasand and Bitumount projects, proposed the development of a second, larger mining and upgrading plant in the early 1970s. Concerns about high construction costs and volatile oil prices caused the project sponsors to reconsider their plans. Financial participation by the federal and provincial governments, and an exemption from the federal oil price controls then in place, allowed the project to proceed. Syncrude began producing upgraded crude oil in 1978.

Two other mining proposals put forward in the late 1970s and early 1980s, the Alsands and the Other Six Leases Owners (OSLO) projects were cancelled because they were deemed to be uneconomic.

3.5.5 First Commercial In Situ Projects

Although there were many early attempts at in situ recovery, among the most colorful and persistent of its proponents was J. O. Absher. In spite of personal injury and financial hardship, Absher pursued his ideas for more than a decade in the 1920s and 1930s. He drilled wells and set up apparatus to inject steam downhole and pump out the heated bitumen. Although he was able to produce very small quantities of bitumen, his plans lacked the technical sophistication to be successful.

The first large-scale in situ project was developed by Imperial Oil Limited at Cold Lake, which started operation in 1978. The Shell Canada Limited project at Peace River began commercial operations in the early 1980s. Both projects involve a form of steam injection that heats the bitumen downhole and enables it to flow and be pumped to the surface.

3.6 Conclusion

The early days of oil sands exploration and development are replete with stories of men of courage and dedication who endured hardship and disappointment to follow their vision.

The first holes were drilled in search of "free oil" thought to feed the oil sands, but this idea was soon disproven. Although many saw value in the oil sands as a road-paving material, transporting the oil sand from such a remote location was not economically feasible. As the need for transportation fuels increased, efforts to realize the oil sands value as a petroleum resource accelerated.

Sidney Ells was a federal civil servant who is largely responsible for the early exploration and delineation of the oil sands deposits. He saw the promise in the oil sands and was a tireless champion of its development.

Dr. Karl Clark represented the provincial government through the Alberta Research Council, and his genius and dedicated work led to the perfection of the hot water extraction process that provides the basis for the extraction process used by the integrated mining plants at Fort McMurray.

The Blair Report, released in 1950, indicated that the oil sands mining and bitumen extraction would be economically feasible. This, plus a more favourable provincial leasing policy, encouraged industry to pursue oil sands opportunities. This paved the way for commencement of the first integrated oil sands mining/upgrading operation in 1967, by GCOS, and a subsequent plant operated by Syncrude, which started in 1978. By the same token, industry was also encouraged to pursue in situ research and development activities. In the 1960s and 1970s, there were many pilot projects, testing various recovery methods. The first commercial in situ recovery project was started by Imperial Oil at Cold Lake in 1978.

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b) Ibid.

c) Ibid.

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e) Ibid.

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g) Alberta Natural Resources. *Oil Sands and Heavy Oils of Alberta*, 1982.

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A REVIEW OF OIL SANDS TECHNOLOGY

4.1 Introduction

The evolution of the Canadian oil sands industry from the first primitive attempts at bitumen extraction to today's dynamic, large-scale, commercially successful operations is a story of remarkable achievement. Through scientific research and technological innovation, a dynamic industry with a wide-ranging support infrastructure has been created that has made Canada the world leader in oil sands development. This success story is due in large part to the vision of the individuals and organizations that steered the research efforts and technological development, and the many dedicated scientists, engineers, technologists, inventors and tradespeople that carried it out.

This chapter presents a brief description of the methods or processes used in the integrated mining/upgrading operations, in the in situ operations and in primary bitumen production. The major technological innovations are identified. Many of the advances in the technology and processes employed were as a result of continuous improvement and were incremental in nature; however, there were some important "step-changes" that occurred as well. Most of these step-changes involved important innovations that were put into practice in the 1990s. It is convenient to describe the changing technology in terms of "old" versus "new".

In addition, a brief discussion of the current areas of research is provided to highlight the important role of science and technology in advancing the oil sands industry.

4.2 Integrated Mining/Upgrading Plants

4.2.1 Mining

Before the oil sands can be mined, the water-laden muskeg that overlies much of the area must be drained, and the layers of muskeg, surface vegetation and tree cover removed. Any suitable soil materials are selectively excavated and used in the ongoing reclamation program. The overburden beneath the muskeg consists of a mixture of rock, clay and barren sand and is removed by trucks and shovels and placed in previously mined-out areas. The removal of the overburden exposes the deposit of oil sands. The oil sands are typically 40 to 60 metres thick and sit on top of relatively flat limestone beds.

The initial mining system that was developed for the GCOS operation was patterned after methods being used in other parts of the world. Two giant bucketwheel excavators were imported from Germany. Especially designed for this project, these machines stood 30 metres high, had a 10 metre diameter bucketwheel attached to a 64 metre long boom and were able to dig out 91 000 tonnes of oil sands daily.[1] The bucketwheels discharged their load on to conveyor belts which transported the oil sands material to a dump pocket near the extraction and upgrading facilities. The series of conveyor belts were typically a kilometre or more in total length. The Syncrude operation, which commenced in 1978, was based on the same system, except huge draglines were used to remove material from the mine face and place it in windrows from which bucketwheel reclaimers loaded it on to conveyor belts. Over the years, continuous improvement in the mining processes took place, including the development of larger capacity bucketwheels, draglines, trucks and power shovels.

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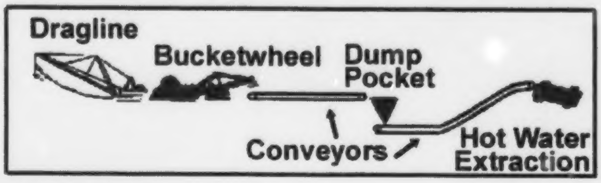
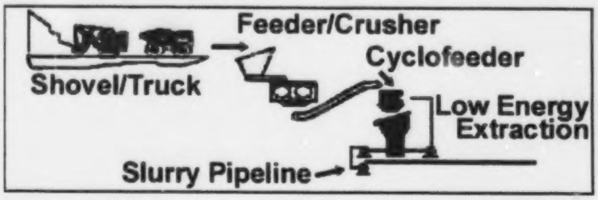
[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

FIGURE 4.1



Old Method



New Method

The massive, complex equipment was difficult and costly to redeploy in the mine (Figure 4.1). In addition, it was vulnerable to interruption of service, especially during cold winter months, due to the potential bottlenecks and many moving parts.

The use of large mining trucks and power shovels in the mining operations became more prevalent as their capacity increased. By the early 1990s, Syncrude was moving about one-third of its ore via this method, and Suncor converted to truck and shovel in 1993. The truck and shovel method is considerably more flexible and less prone to interruption of service. Today, the oil sands ore is commonly moved to the dump pits by trucks capable of hauling 360 tons that are loaded by power shovels with 58 cubic yard capacity buckets.

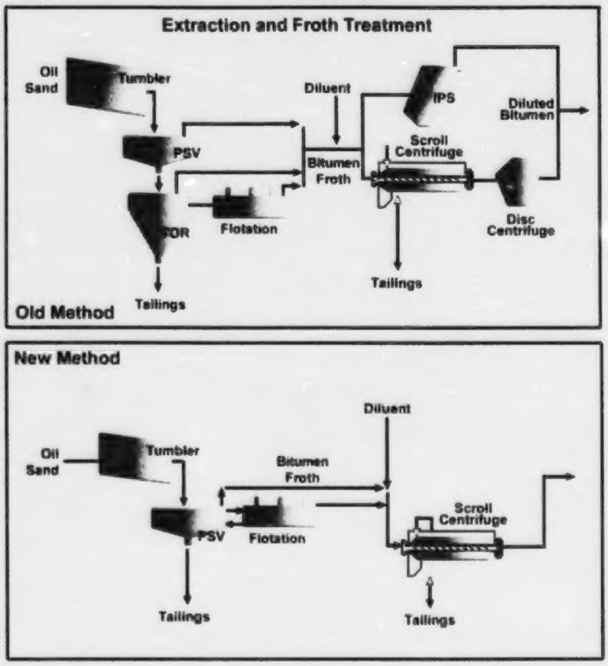
As well, the dump pocket has been modified to include a feeder/crusher system in which the oil sands are fed through a double roll crusher.

In the 1980s, the Other Six Lease Owners (OSLO) consortium patented the OSLO Cold Water Extraction process that included the transporting of a water/oilsands slurry via pipeline to an extraction plant. Based on this system, Syncrude developed a hydrotransport process in the early 1990s that provides a much cheaper and more flexible method to transport oil sands compared to the old system of long conveyors.

The first step in this process features an important new innovation, the cyclofeeder, a massive vessel nearly 35 metres tall. In the cyclofeeder, the oil sands are crushed and mixed with hot water to form a slurry which is then fed at high speeds into a pipeline and transported to an extraction plant, which could be many kilometres away. The benefits of this system include:

- the break down of large lumps of oil sands in the ore and some separation of bitumen from oil sands as the slurry moves through the pipeline;
- much more flexibility, because pipelines can follow circuitous routing and be placed on uneven terrain; and,
- low energy extraction — because of separation during hydrotransport, operating temperatures can be reduced to 50°C, or less.

FIGURE 4.2


Extraction and Froth Treatment
Oil Sand
Tumbler
PSV
TOR
Flotation
Tailings
Diluent
Bitumen Froth
IPS
Scroll Centrifuge
Diluted Bitumen
Disc Centrifuge
Tailings
Old Method
New Method
Diluent
Oil Sand
Tumbler
Bitumen Froth
PSV
Flotation
Scroll Centrifuge
Tailings
Tailings

A recent innovation by Syncrude, called "Natural Froth Lubricity", uses water in the froth to create a lubricating sleeve, thereby allowing the pipelining of froth without adding diluent.

The hydrotransport system has been adopted by Suncor, and is planned for the Athabasca Oil Sands Project being constructed by Shell Canada Ltd. (Shell) and partners. Compared to the old conveyor method, this system allows mining to be carried out at much greater distances from the extraction plant. It is expected that by 2005 all of mined oil sands in Alberta will be transported using hydrotransport technology.

The efficiencies gained in mining operations by converting to truck and shovel, and the development of the hydrotransport system are the principal reason operating costs have been reduced by about 50 percent in the last decade. Operating costs are currently in the $11 to $14 per barrel range, with a target of $10 or less before 2005.

4.2.2 Extraction

The bitumen extraction processes initially used by GCOS and Syncrude were based on the Hot Water Extraction Method perfected by Dr. Karl Clark at the Alberta Research Council (Figure 4.2). Oil sand ore is moved from the base mine dump pocket by conveyor and enters large rotating tumblers where the ore is slurried by steam, hot water (85°C) and caustic soda to condition it for bitumen separation. The aerated slurry from the tumblers discharges onto vibrating screens where large materials such as rocks and lumps of clay are rejected. The slurry is diluted in pump boxes and pumped to the Primary Separation Vessels (PSV), where bitumen rises to the surface as a froth and is skimmed off, while the sand settles to the bottom. The froth is moved to a flotation unit in which air-bitumen bubbles rise to the surface. Froth treatment is required to minimize the amount of water and solids going to the upgrader, so at this point naphtha is added as a diluent and the mixture enters a high speed centrifuge to complete the cleaning or separation. The diluted bitumen is moved to the upgrading unit while the sand and other material that settles during the separation process are removed as "tailings slurry".

New innovations include (Figure 4.2):

- the addition of the Tailings Oil Recovery (TOR) vessels — a technology developed by Syncrude, these deep cone vessels recover most of the remaining bitumen that was discharged from the PSV as part of the tailings in the old method;
- a secondary flotation unit to receive froth from the TOR;

- inclined plate settlers (IPS), developed by Suncor, and disc centrifuges, designed to provide more complete separation; and,
- a Diluent Recovery Unit (DRU), developed by Syncrude to recover naphtha from all froth treatment tailings.

Today's extraction processes are able to extract about 91 percent of the bitumen contained in the oil sands, compared to about 84 percent in 1975. The energy savings derived from the low energy extraction process also contribute significantly to lowering operating costs.

The Athabasca Oil Sands Project, planned by Shell and partners for startup in early 2002, includes a major innovative feature. The "multi-stage counter-current decantation" process provides partial upgrading in the field. In this process the extracted bitumen is blended with a paraffinic solvent which promotes the precipitation of asphaltenes, and thereby removes most of the carbon-laden or coke-producing components in the mixture. This fits with the project's plans, in that the associated Scotford Upgrader at Shell's refinery is based on hydrogen-addition technology and, therefore, will not require a coking unit.

4.2.3 Tailings Disposal

The tailings produced as a result of the extraction process consist of a mixture of water, sand and fine clay particles. The traditional method to deal with tailings has been to pump them into large holding ponds with reclamation to occur after the tailings slurry solidifies. However, the microscopic sized clay particles could stay in suspension for hundreds of years before settling out.

Suncor, in association with the Consolidated Tailings Consortium, has developed a new technology called consolidated tailings (CT) which uses gypsum, produced as a by-product from its flue gas desulphurization unit, to greatly accelerate the transformation of tailings into solid material. Other mining operations have adopted the same technology. With CT, reclamation of the tailings ponds is expected to take 10 years or less. Further discussion of tailings can be found in Chapter 9, Section 3.1.

4.2.4 Upgrading

During the upgrading process the bitumen is converted from a viscous, tar-like oil that is deficient in hydrogen and high in sulphur and heavy metals, to a high quality "synthetic" or "upgraded" crude oil that has density and viscosity characteristics similar to conventional light sweet crude oil, but with a very low sulphur content (0.1- 0.2 percent). This upgrading is achieved through a process of coking, desulphurization and hydrogen addition.

The first step in upgrading is recovery of naphtha, which is removed and recycled back to the extraction plant. The bitumen is then heated in furnaces and sent to a vacuum unit where some of the product is removed. The remaining bitumen is forwarded to cokers where high temperatures in the coker's reactors cause the long bitumen molecules to thermally crack. Most of the bitumen vapourizes into gases, but the heavy bottom carbon-rich material forms coke. Suncor uses a delayed-coking technology while Syncrude uses a somewhat different process called fluid-coking. Coke is used as a fuel source for the coker burners as well as for other heat requirements. The excess coke is stockpiled or sold for use in ammonia plants or other industrial applications.

The remaining hydrocarbon vapours are sent to fractionators where they are separated into naphtha, kerosene and gas oil. Within the hydrotreater units the hydrocarbon vapours react with hydrogen at high pressure and high temperatures in the presence of a catalyst. This process is used to stabilize the product stream as well as to remove sulphur and nitrogen. The product streams of naphtha and gas oils from the hydrotreaters are blended to make a high grade crude oil. The sulphur is converted to elemental sulphur and stored on site or shipped to market, while the nitrogen is removed as ammonia and generally used as a fuel in the utilities plant. Fuel gas, produced as a by-product of the refining process, is sweetened and then sent to amine units for hydrogen sulphide removal. The resulting sweet gas is used throughout the plant as an energy source.

Major new innovations in upgrading include:

- the LC-Finer hydroprocessor, which breaks down bitumen through hydrogen addition over an ebullated catalyst bed to produce a cracked light gas oil; and,
- the installation of a vacuum distillation unit (VDU) to remove volatile material from the bitumen before it enters the cokers, thus eliminating the cokers as a process bottleneck.

4.3 In Situ Recovery

For oil sands reservoirs too deep to support economic surface-mining operations, some form of in situ recovery is required to recover the bitumen. The EUB attributes about 80 percent of the total bitumen ultimately recoverable from Alberta's oil sands, or some 39 billion cubic metres, to in situ recovery methods. This represents a target with huge potential.

In general, the heavy, viscous nature of the bitumen (8-10° API, 10 000 - 300 000cp) within the sub-surface deposits means that it will not flow under virgin temperature and pressure conditions. Thus, thermal energy must be applied to heat the bitumen sufficiently to allow it to flow to a well bore and be produced. Alternatively, dilution with a solvent can also induce the bitumen to flow. As an exception to this general rule, there are reservoirs in the Wabasca area and in the southern part of the Cold Lake area where the oil is sufficiently fluid to allow primary or "cold" production.

From the early 1900s there have been many attempts at in situ recovery, but most were primitive in design and only very small amounts of bitumen were produced. It was not until the 1950s that improved technology allowed in situ development to move forward.

A wide variety of recovery methods have been tested, either alone or in combination with other methods. These include stimulation by various means, such as: steam injection; in situ combustion; the application of ultrasound, microwave, and electromagnetic energy; and, the injection of water, polymers, alkalines and solvents. As an indication of the activity level, the EUB lists 340 projects, beginning in 1959, for which some type of experimental recovery test was approved.[a] Today, there are some 22 active in situ bitumen projects situated in all three oil sands areas, consisting of 11 commercial projects and 11 experimental projects, with most of these employing some form of steam stimulation.

4.3.1 Cyclic Steam Stimulation

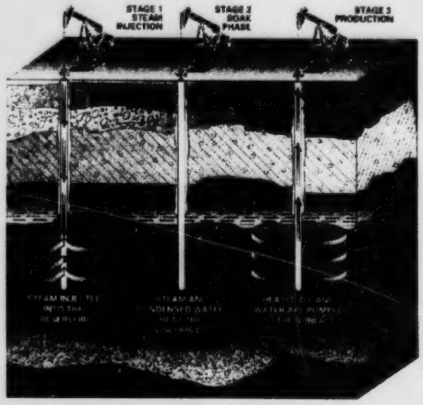
The cyclic steam stimulation (CSS) system was developed by Imperial Oil Ltd. at Cold Lake. Exploratory drilling between 1958 and 1962 led to the establishment of the Ethel pilot project in 1964. Several recovery schemes were tested including cyclic steam injection and in situ combustion. By 1975, through the operation of the Ethel pilot and a new pilot, called May, Imperial had demonstrated the technical feasibility of CSS at Cold Lake.[b] A third pilot plant at Lemming provided the basis for moving to commercialization with CSS technology in 1985.

Innovations at the time included recycling of produced water and the pad drilling concept — drilling 20 wells from one pad became the standard.

The CSS or "huff and puff" system (Figure 4.3) is based on producing steam in large boilers and injecting it down the well bore into the target formation at a temperature of about 300°C and pressures averaging 11 000 kilopascals. This level of pressure is sufficient to fracture the formation rock creating a path for fluid flow. For each individual well, periods of steaming are followed by periods of soaking and then by periods of production. When production rates decline, another cycle of steam injection begins. Cycle times are typically six to eighteen months. It is expected recovery factors of about 20 to 25 percent will be achieved with CSS.

FIGURE 4.3

Cyclic Steam Stimulation


STAGE 1
STEAM
INJECTION
STAGE 2
SOAK
PHASE
STAGE 3
PRODUCTION
STEAM INJECTED INTO THE RESERVOIR
STEAM AND CONDENSED WATER HEAT THE VISCOUS OIL
HEATED OIL AND WATER ARE PUMPED TO THE SURFACE

Courtesy of Imperial Oil Ltd.

At the end of 1999, Imperial was operating about 3 000 wells at Cold Lake, with production of nearly 21 000 m^3/d. Although CSS has proven to be very successful for Imperial at Cold Lake, it has not been widely applied elsewhere.

4.3.2 Pressure Cycle Steam Drive

In the 1960s, Shell began experimental work on its Peace River leases with three small pilot projects. A 1973-1974 test achieved high steam injection rates without fracturing, and with excellent production response.[c] In partnership with the Alberta Oilsands Technical Research Authority (AOSTRA) in 1979 the pressure cycle steam drive system was developed. This process takes advantage of a basal water zone, which underlies the oil sands in this area, to heat the oil sands deposit from below. Once a hot communication path is established between wells, continuous steam injection is begun, with the injection and production rates controlled to alternately pressure up and blow down the reservoir.[d] Shell proceeded to commercial operation with the Peace River Expansion Project in 1986. Although a technical success, in the 1990s this project evolved into a combination of SAGD development and multilateral wells employing steam injection.

4.3.3 Steam-Assisted Gravity Drainage

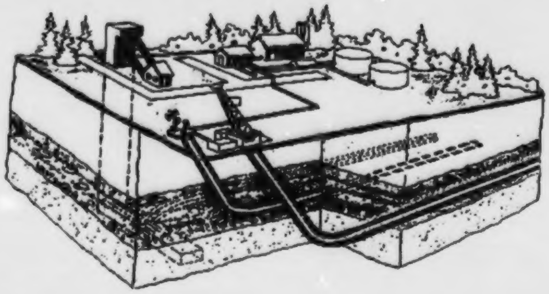
Dr. Roger Butler, now with the University of Alberta, first envisaged the SAGD process and developed the theoretical basis for it during the late 1970s and early 1980s. He was interested in developing a system that utilized continuous heating and production, rather than the discontinuous CSS process. Dr. Butler, after determining that vertical wells production rates were too low to make SAGD economically viable, conceptualized SAGD that used horizontally oriented wells. He subsequently developed theoretical predictive equations to support this idea. The SAGD test was conducted at Cold Lake in 1978, and Imperial drilled the first horizontal well for this purpose. Steam was injected from a vertical well directly above the horizontal producer. Results of this first test were marginal.

SAGD was the first process tested by AOSTRA at its Underground Test Facility (UTF) near Fort McMurray, in 1983 (Figure 4.4). This facility has a system of vertical access shafts and horizontal tunnels that allows the placing of pairs of horizontal wells within the oil sands deposit at a depth of about 200 metres. Each well pair consists of a producer situated near the base of the oil sands and an injector about five metres directly above the producer. Steam is injected through the upper well and heats the oil sands and bitumen. Provided there is sufficient permeability, the mobilized bitumen and condensed steam drains by gravity to the producing well, and is subsequently pumped to the surface. The depletion zone, or steam chamber, is enlarged as the bitumen is removed. Since steam is injected at below fracture pressure, it is contained within the steam chamber, thereby enhancing the heating efficiency of this method.

Encouraged by the 60 percent recovery factor achieved in the first phase of the project, subsequent phases were carried out to conduct further research.

FIGURE 4.4

Underground Test Facility



Courtesy of AOSTRA.

Horizontal drilling technology developed rapidly in the late 1980s and early 1990s. For SAGD, the orientation and the separation distance between the injector well and the producer well has to be precisely controlled, and this capability was available by the mid-1990s. Beginning in 1996, several well pairs were drilled from the surface at the UTF site, and the performance of these wells was comparable to those that had been drilled from the tunnels.

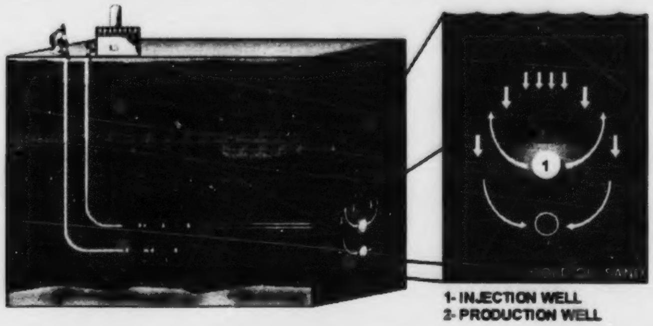
An additional vital contribution made by AOSTRA was the development of a computer simulation program to optimize the design and operation of SAGD in horizontal wells. Techniques to control sand production and to prevent steam from entering the producing well bore were also developed as part of the UTF project.

The UTF project indicated that SAGD was technologically and economically feasible. Today's SAGD operations are built on this model (Figure 4.5). The ability to cost-effectively drill long-reach horizontal wells, typically hundreds of metres in length, and to precisely control the positioning of these wells relative to each other and to the boundaries of the target formation, is a major enabling technological achievement that has allowed the development of SAGD technology. The UTF project is now known as the Dover Project and is operated by Northstar Energy Ltd.

SAGD technology offers some potential advantages over CSS. These include lower steam-oil ratios which reduce operating costs, and the use of lower pressures which allow exploitation of shallower reservoirs. Although not yet proven to be commercially viable on a large scale, industry's confidence in the process is demonstrated by the fact that there are currently six commercial SAGD projects planned to start-up before 2005 (see Chapter 6, Section 6.4.3 and 6.5.1).

FIGURE 4.5

Steam-Assisted Gravity Drainage (SAGD)

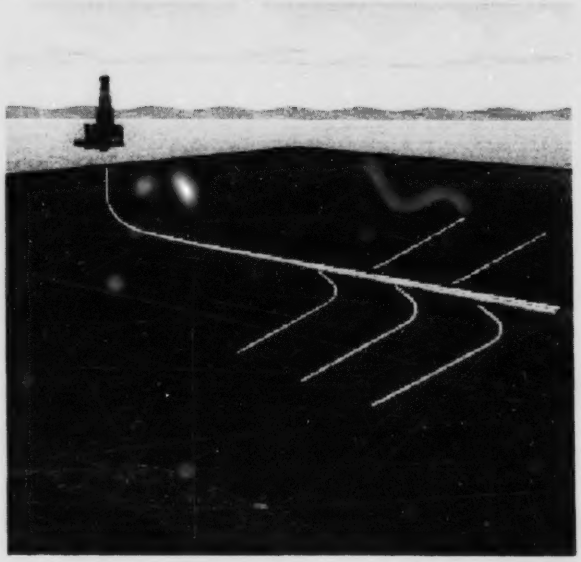


4.4 Primary Bitumen Recovery

There are reservoirs in the Wabasca area and in the southern part of the Cold Lake area where primary or "cold" production is possible; that is, no external energy is applied to the reservoir to induce the bitumen to flow to the well bore. The bitumen in these areas has undergone a lesser degree of biodegradation in comparison to the other areas, and is therefore lighter and less viscous and flows more readily.

FIGURE 4.6

Multilateral Horizontal Well



4.4.1 Cold Lake

Within the Cold Lake areas amenable to primary production, most projects use vertical wells. Before about 1990, the sand that was produced along with the bitumen was problematic, causing extreme wear on pumping components and reducing production rates and overall productivity. The wide-scale adoption of the progressive cavity pump in the early 1990s was a significant innovation. This type of pump was much better suited to handling sand; in fact, operators found that producing sand along with the oil, especially early in a well's life, was conducive to higher production rates. It was determined that a system of preferential fluid flow paths, or "wormholes" formed and expanded as the sand was produced. This resulted in significantly higher production rates, lower operating costs and improved economics. Recovery factors range from three to ten percent.

4.4.2 Wabasca

In the Wabasca area, early attempts at production using vertical wells yielded low production rates. It was not until the advent of horizontal well technology in the 1990s that interest in the area heightened. The reservoirs are relatively thin (five metres) and consolidated, with no significant sand production problems, and better suited to primary production by means of horizontal wells. The horizontal well technology has advanced to the stage that very long single leg and even "multi-leg" or "multilateral" producing wells can be drilled and successfully operated (Figure 4.6). As an example, wells with up to seven legs and with a total length of 15 kilometres are being drilled from a single well bore. Recovery factors are expected to be in the range of seven to ten percent.

4.5 Science and Technology

Although research and development efforts related to oil sands are concentrated in Alberta, they are being carried out in virtually every province in Canada, and in many parts of the world, encompassing a wide array of scientific disciplines and technologies. The broad objectives of the ongoing research are to lower unit production costs, expand the size of the recoverable reserves volume, and, at the same time, improve environmental performance and product quality.

The discussion in this section will be limited to a brief description of the major current research efforts, in each of three broad areas: mining and extraction; upgrading; and, in situ recovery. Some specific examples of major new technological developments are also provided.

4.5.1 Mining and Extraction

The sand component of the oil sands is very abrasive and causes excessive wear on mining and extraction equipment. Although many improvements have been made to date, as noted above, research into reducing wear through the development of improved materials and processes is still important.

The present trend to increasingly larger mining trucks and power shovels is expected to continue. Trucks capable of hauling loads of 500 tons are expected within this decade. Associated areas of research and development include the design of tires as well as engine and drive train components.

The development of a system to remove ore at the mine face with a high pressure water jet and transporting an oil sands slurry by pipeline is an attractive idea, provided that sufficient quantities can be moved in this fashion to make it economic.

Mobile mine-site extraction technology is expected to be a key breakthrough of the future. Mobile extraction operations located near the mine face would allow the direct return of waste sand back to the mine. This form of technology could potentially reduce capital costs and allow operations on a smaller scale.

Research continues into the new CT system of tailings disposal, as well as a new method termed "paste" technology.

4.5.2 Upgrading

The current technologies used in the integrated mining plant upgraders are very energy intensive and depend on hydrogen as a source for hydroprocessing. The broad objectives of upgrading research is to lower unit production costs while, at the same time, improving environmental performance and product quality. Ongoing research includes the study of:

- methods to improve energy efficiency;
- methods to reduce harmful emissions;
- the emissions characteristics of transportation fuels made from upgraded crude oils;
- improvements to existing delayed coking and fluid coking technology;
- fine solids/catalyst interaction during hydrotreating; and,
- fluidized bed systems.

Some specific examples are provided below to illustrate the variety of technological innovations being pursued:

- Aquaconversion™, an upgrading process which utilizes certain additives that when processed in a visbreaker in the presence of heavy oil and steam, result in the transfer of hydrogen from the steam into the oil[*] — this process was developed in Venezuela, and is being tested in that country's Orinoco field; and,

- the BioARC (Biocatalytic Aromatic Ring Cleavage) project which is being conducted by a group at the Centre for Oil Sands Research and Development, using designed strains of bacteria to provide controlled degradation of petroleum feedstock to reduce the need for hydrogen addition.[f]

Processes that provide partial upgrading can benefit large scale upgrading operations, but they also have application for in situ projects. One of the major problems facing bitumen producers is the need to dilute the bitumen with condensate in order to meet pipeline specifications for density and viscosity. Partial upgrading to meet these specifications, that could be done on a relatively small scale and close to the production facilities or within the reservoir, is an attractive proposition. In this regard, two novel methods are:

- the $(HC)_3$ or high conversion/hydrocracking/homogenous catalyst process,[g] developed by the Alberta Research Council, and adapted to partially upgrade bitumen; and,
- a process developed at the University of Waterloo for the treatment of heavy oil emulsions that provides both dewatering and upgrading in a single reactor, using hydrogen generated from water in the emulsion.[h]

4.5.3 In Situ

The vapour extraction process (VAPEX) is similar to SAGD in that gravity drainage is the drive mechanism and a pair of horizontal wells are used for injection and production. Instead of steam, VAPEX involves injecting solvent, which diffuses into the bitumen and results in significant viscosity reduction. Compared to SAGD, VAPEX has the advantage of:

- lower injection pressure and temperature;
- much greater energy efficiency;
- no emulsion to deal with;
- no formation damage from clay swelling; and,
- partial upgrading within the reservoir, resulting from the precipitation of asphaltenes from the bitumen.

4.5.4 Primary Production

Regarding primary production, areas of research include:

- the characteristics of wormhole formation and the associated fluid flow processes;[i]
- improvement in horizontal well design, drilling, and operation; and,
- improvement in lifting systems.

4.6 Conclusion

The initial mining operations at both Suncor and Syncrude were based on a system of large draglines, bucketwheels and conveyors belts to mine the oil sands and move it to extraction facilities. This system proved to be relatively inflexible and costly to maintain. Although a process of continuous improvement served to improve the project economics, major innovations in the 1990s, namely truck and shovel mining, hydrotransport, and low energy extraction, greatly reduced operating costs.

Although many in situ recovery methods were pilot tested in the 1960s and 1970s, only the steam stimulation techniques in high quality reservoirs proved to be technically and economically successful. Imperial's Cold Lake CSS project is the best example of this.

Research and testing conducted at the UTF project, in combination with significant advances in horizontal well technology, led to the development of the SAGD bitumen recovery method. Although not commercially tested on a large scale, this new technology shows great promise. The application of SAGD is expected to greatly increase the volume of resources deemed to be economically recoverable.

Science and technology has always played a vital role in the oil sands industry, and research is ongoing into a wide variety of problem areas. The main objectives of the research is to lower costs while improving product quality and environmental performance.

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CHAPTER FIVE

SUPPLY COSTS

5.1 Introduction

This chapter presents a discussion of supply costs for both oil sands mining and in situ projects, including primary bitumen production. A brief description of the new fiscal regime for oil sands is also included.

In this report, "oil sands mining" generally refers to integrated surface-mining and upgrading operations, but also includes stand-alone surface-mining projects. "Oil sands in situ" refers to all in situ operations, including primary bitumen recovery operations.

5.2 Methodology

As in previous Board reports, supply costs are expressed as full cycle, which includes all costs associated with exploration, development and production. They include capital costs, operating costs, taxes and royalties and a 10 percent real rate of return to the producer. Accordingly, they include all those environmental costs that have been internalized through the implementation of mitigation methods, such as those discussed in Chapter 9, or capitalized as a production cost. They do not include any costs to society associated with environmental impacts which have not been mitigated. The exploration costs associated with the oil sands are minimal because the location and extent of the oil sands deposits have been well defined by past exploratory efforts. Although drilling and seismic surveying are being done, this is largely geared toward reservoir development. The Board's estimates of supply costs are based on discussions with industry, consideration of the announced development plans for mining and in situ projects, research of the trade literature and the Board's own analysis. Supply costs are quoted in 1997 Canadian dollars per barrel unless otherwise noted. These costs do not include transportation to market.

The economic assumptions used in this report are the same as those contained in the Board's Supply and Demand report, including a world crude oil price of US$18 per barrel for WTI. While crude oil prices are expected to be volatile, US$18 is still considered by oil market analysts to be a reasonable assumption for the longer term.

Supply costs are stated as a range, reflecting the variance in reservoir quality, depth, project size and operating parameters for the projects being developed.

5.3 Oil Sands Mining Projects

5.3.1 Supply Costs - Oil Sands Mining

The first two large-scale commercial mining projects, Great Canadian Oil Sands Company (now Suncor), which began operations in 1967, and Syncrude, which commenced in 1978, suffered from start-up problems, and it took several years for reasonably smooth production operations to be established. Early supply costs are estimated to have been $35 per barrel or above (dollars of the day). In reaction to high supply costs, sustained periods of low oil prices, and overall uncertain crude oil prices, oil sands mining developers concentrated on cost reduction to improve the economics of oil sands production. As a result, operating costs have trended downward. Between the early 1980s and the late 1990s, operating costs have been reduced from $30 per barrel to less than $13 per barrel.[a] Capital cost requirements were also reduced such that current total supply cost estimates are in the range of $15 to $18 per barrel for an integrated oil sands mining and upgrading operation.

Substantial reductions in supply costs were achieved through continuous process improvement; however during the 1990s there were two major innovations which resulted in large reductions in operating costs. First, there was a move towards replacing the draglines and bucketwheel reclaimers with mining trucks and power shovels. This equipment offered increased flexibility, lower maintenance and improved energy efficiency. Second, the introduction of the hydrotransport system to replace the conveyor belts to transport oil sands to the processing plant was a major innovation, again resulting in increased flexibility and energy efficiency. Several other changes were also important and cumulatively have had a significant effect on operating costs although they did not result in a step reduction. These changes included improved tailings management, the switch to cyclofeeders from breakers and the low temperature extraction process.

5.3.2 Supply Cost Projections - Mining

Industry analysts anticipate that continuing improvements in technology and operating methods may bring operating costs (dollars of the day) for integrated mining/upgrading plants down to $10 per barrel as early as 2004, with further improvement to the $8 to $9 per barrel level by 2015.

A major cost component for upgrading bitumen is the price of natural gas which is used to generate electricity and steam, and is also a source of hydrogen used in the upgrading process. It is estimated that an increase in the natural gas price of $1.00/GJ increases operating costs by about $1.00 per barrel. Under a high natural gas price scenario the reductions in operating cost will be more difficult to achieve. By the same token, there is some degree of linkage between oil and gas prices; that is, if oil prices moderate there would be some downward pressure on gas prices as well.

Table 5.1 outlines the operating costs and total supply costs (everything in) for the production of bitumen and upgraded crude oil for the various recovery methods.[1]

TABLE 5.1

Estimated Supply Costs - $(1997) per barrel

Oil Sands - In Situ	Operating Cost	Supply Cost
Primary Recovery - Wabasca	3 to 6	7 to 10
Primary Recovery - Cold Lake	6 to 9	10 to 13
Cyclic Steam Stimulation	6 to 10	10 to 16
Steam Assisted Gravity Drainage	5 to 9	8 to 14
Oil Sands - Mining		
Integrated Mining/Upgrading	10 to 12	15 to 18
Stand-Alone Upgraders	10 to 12	18 to 22
Mining - No Upgrading	5 to 8	10 to 13

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[1] The Base Case assumes an oil price of US$18 per barrel (WTI) at Cushing, Oklahoma, a natural gas price of $2.75 per gigajoule and a light/heavy differential at Hardisty, Alberta of C$5 per barrel, all 1997 dollars, constant, real.

5.4 In Situ Projects

5.4.1 Supply Costs - In Situ

In situ production has not achieved step reductions in supply costs similar to those for the mining operations. However, there have been important innovations and improvements that have reduced costs. Among these are significant advances in horizontal well technology in the last decade that have led to:

- reduced drilling costs;
- the ability to drill and complete extended-reach and multi-leg wells, thereby greatly increasing the volume of reservoir contacted per well; and,
- the ability to accurately guide the drill bit while drilling, which was an enabling technology for the SAGD recovery method.

The development of SAGD is also a major innovation. It is expected to have lower costs, in general, than CSS, because high steam pressures are not required, and because of the efficiencies achieved through using horizontal wells.

Other innovations include:

- improved steam and heat management in CSS operations, by varying the time and steam volume during each cycle;
- better reservoir management;
- improved well work-overs;
- reduced rig time to drill and complete new wells;
- computer simulation and new seismic survey techniques for analysing and forecasting reservoir performance;
- combined-cycle cogeneration plants to obtain high thermal efficiency in steam generation;
- control and measurement of steam flow in distribution piping; and,
- more efficient separation and treatment of produced oil and water.

These and other innovations and technologies have significantly lowered both operating and capital costs. In situ producers can further lower supply costs per barrel by taking advantage of economies of scale.

Bitumen typically requires that about 33 to 40 percent of diluent be added (25 to 30 percent of blend) to meet pipeline specifications for density and viscosity. The availability and cost of natural gas condensate or other diluents to blend the bitumen can also affect the feasibility of in situ bitumen projects.

In certain areas of the Cold Lake and Wabasca deposits, bitumen can be recovered by primary or "cold production" means. In the Cold Lake region, this type of production typically employs vertical well bores coupled with progressive cavity pumps that are well suited to handling sand. Primary production in the Wabasca area typically employs horizontal wells, both single-leg and multi-leg, with horizontal sections as long as 2 000 metres. Supply costs are in the range of $10 to $13 per barrel for primary production in Cold Lake while the Wabasca area has slightly lower costs, in the $7 to $10 per barrel range.

5.4.2 Supply Cost Projections - In Situ

The first attempts at in situ recovery of bitumen from oil sands occurred in the Athabasca region in the 1920s and 1930s, but met with little success. In the 1960s and 1970s, a series of exploration and research efforts led to a wide variety of pilot projects. Most of the projects did not pass the test of technical and economic feasibility.

Currently, about 67 percent of in situ bitumen production is derived from thermal projects involving some form of steam stimulation. The remaining 33 percent is from primary production projects. For the steam stimulation projects, the cost of the fuel used to produce the steam can account for 50 percent or more of the total operating cost. The operating costs of producing in situ bitumen have considerable variation, ranging from about $3 to $10 per barrel. These operating costs are very dependent on the recovery method, recovery rate, peak production level and the steam/oil ratio for thermal projects. Considering that natural gas consumption is by far the largest cost component of in situ production, any changes in gas prices or any improvements in thermal efficiency in steam generation will have a significant impact on operating costs. Estimates of supply costs for in situ production are shown in Table 5.1.

Although the SAGD recovery method has not yet been commercially proven in bitumen reservoirs, the success of the UTF pilot project and the successful application of SAGD in several conventional heavy oil reservoirs has given industry confidence in this technology. There are currently six publically announced commercial scale SAGD projects scheduled to begin operation before 2005. In order to assess the potential for SAGD development, the Board conducted an analysis of supply costs for SAGD. A range of supply cost estimates for SAGD production were developed by considering the effect of variations in the natural gas price, project size and reservoir quality. Reservoirs of four different qualities were considered, consisting of a higher and lower quality reservoir in the Athabasca area and a higher and lower quality reservoir in the Cold Lake area (Figures 5.1 and 5.2).

A further description of the methodology and assumptions used in this analysis are contained in Appendix A-2.

The supply costs vary widely depending on the scenario chosen, with costs ranging from $22.50 per barrel, for the combination of a low quality Cold Lake deposit, a $5.00/GJ natural gas price and a 3 000 m^3/d plant size — to $6.00 per barrel for the combination of a high quality Athabasca deposit, a $2.00/GJ natural gas price and a 16 000 m^3/d plant size. While the supply cost is sensitive to the natural gas price and economies of scale, the quality of the reservoir is the most critical factor. Given a natural gas price of $3.00/GJ and a plant size of 8 000 to 10 000 m^3/d, the better projects would have a supply cost in the order of $10 to $12 per barrel in the Cold Lake area and $8 to $10 per barrel in the Athabasca area. This compares with the supply cost for conventional heavy crude oil of $9 to $10 per barrel, before consideration of relative transportation costs. A price of US$18 for WTI, after considering transportation charges, exchange rates, blending costs, and a $5.00 light/heavy differential, translates to a realization of about $11.00 per barrel in the field for SAGD derived bitumen.

FIGURE 5.1

Athabasca Deposits Supply Cost - SAGD

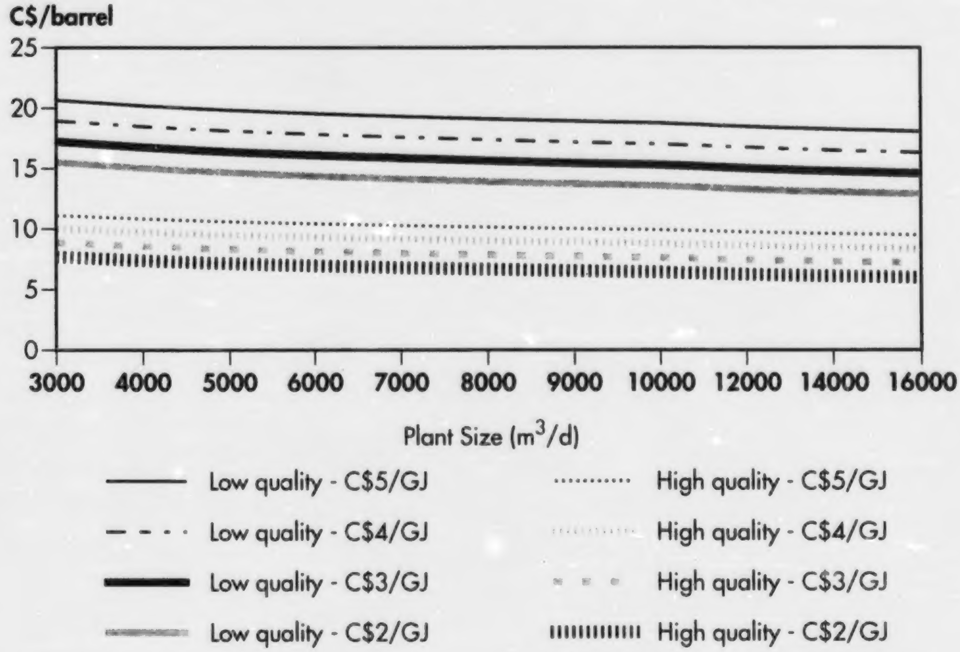
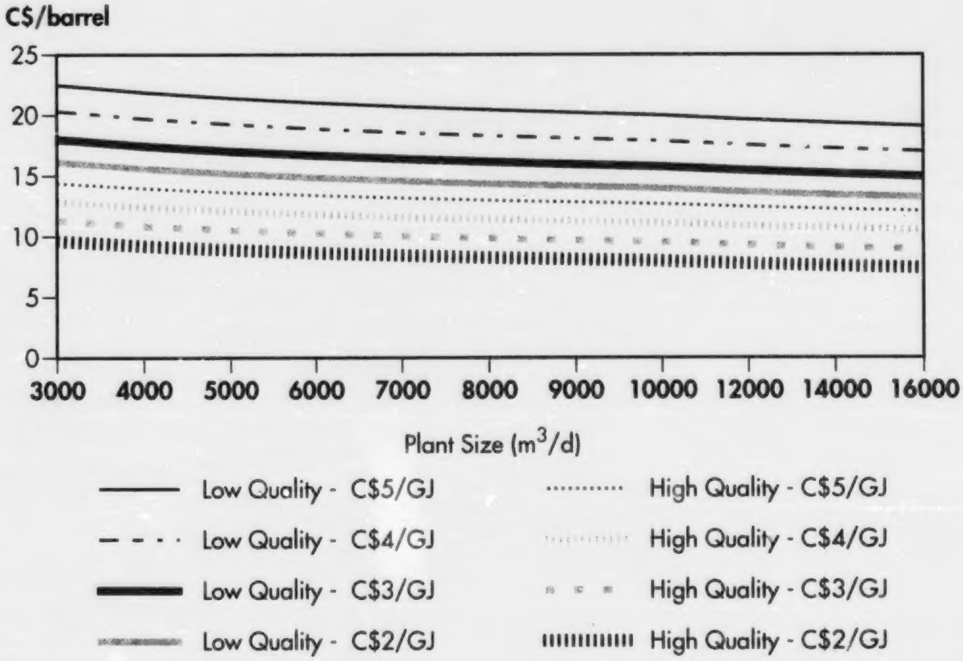


FIGURE 5.2

Cold Lake Deposits Supply Cost - SAGD



5.5 Oil Sands Fiscal Regime

On September 24, 1997, the Alberta Government completed the enactment of a generic royalty regime that will ultimately replace the custom tailored Crown Agreements. The locations affected by the regime include the Athabasca, Peace River and Cold Lake Oil Sands Areas.

The main purpose of the new regime is to provide common rules that apply equally to all oil sands developers. Prior to the generic oil sands royalty system, each project's royalty terms were negotiated on a project-by-project basis. This process was possible due to the limited number of projects that were commercially active in Alberta. These project-specific arrangements in the oil sands industry resulted in an overall inharmonious royalty system. The developers agreed that Alberta's ad hoc oil sands royalty system led to uncertainty about the terms that would apply to their future investments. Investors considering oil sands development did not have a transparent royalty structure on which to evaluate investment plans. As well, existing oil sands companies were not certain about the future royalty structure for new investments or expansions. As a result, there was a need to construct a formal royalty structure for the oil sands industry that would place all projects on a level playing field.[b]

The evolution of the new royalty regime commenced in the spring of 1995 when the National Task Force on Oil Sands Strategies released a comprehensive report that outlined a detailed list of recommendations for the oil sands industry. The Task Force was formed by the Alberta Chamber of Resources in 1993. This committee consisted mainly of representatives from the oil sands industry and supporting industries, as well as representatives from both the provincial and federal governments. The Task Force proposed a generic oil sands royalty system based on a specified percentage of net project revenue after all costs are recovered. The proposal reflected the type of royalty system already in place through various individual oil sands Crown Agreements (i.e., Syncrude, Suncor and Imperial Oil's Cold Lake Project). These Agreements provided a foundation for the Task Force's recommendations and for the Alberta Government's new generic royalty system.

The Task Force recommendations were designed to:

- accelerate the development of the oil sands while ensuring a fair return to Albertans — the resource owners;
- facilitate development of the oil sands by private sector companies who can expect to make a reasonable profit from the venture — governments will not directly participate through grants, loans or loan guarantees;
- ensure that oil sands development is competitive with other petroleum development opportunities around the world; and,
- create a standard set of royalty and taxation terms for new projects to create a clear, consistent and stable system.[c]

5.5.1 New Royalty and Taxation Measures

Alberta used many of the recommendations of the Task Force in developing the standardized oil sands royalty system. The basic elements of the new system are:

- minimum one percent royalty payable on all production;
- 25 percent royalty payable on net project revenues after the developer has recovered all project costs, including research and development costs, and a return allowance;

- return allowance set at the Government of Canada Long-Term Bond Rate; and,
- all project costs including capital, operating, and research and development are 100 percent deductible in the year incurred.

The new generic royalty regime is administered by Alberta Resource Development under the Mines and Minerals Act. It is designed to support the major investment needed to develop the oil sands resource. The regime will apply to new investment in developing Alberta's oil sands and expansions of existing projects. An important feature of the royalty agreement is that Alberta is sharing risk with the developer. Only when the developer's cumulative project revenues exceed cumulative project costs, including a return on investment equal to the Canada Long-Term Bond Rate, does Alberta receive a significant royalty.

This royalty regime was chosen over production-based royalties due to the high cost, long lead time and the associated high-risk nature of oil sands investment. Production-based royalties, such as those used for conventional oil and gas, are less sensitive to project profitability. Since the oil sands have higher barriers to development than other types of petroleum (higher capital and operating costs, less valuable product, higher technology risk, etc.), the additional burden of a significant production-based royalty was determined to be inappropriate.

The federal government, a member of the Task Force, agreed to modify the rules regarding taxation of oil sands production. The 1996 Federal budget provided generic tax treatment for all oil sands projects. The tax treatment previously applied only to oil sands mining projects was extended to include in situ projects. In addition, tax incentives previously available only for new projects and major expansions were extended to include other investments, such as environmental and efficiency improvement projects.

5.6 Conclusion

Supply costs for bitumen production from Canada's oil sands have been substantially reduced through a process of continuous improvement in all aspects of operations and more importantly, through the implementation of major technological innovations, with most of these innovations occurring in the 1990s.

For the existing surface-mining operations, supply costs have been reduced by more than one-half in the last twenty years, with current supply costs in the field estimated to be in the range of $15-$18 per barrel. The adoption of truck and shovel mining, hydrotransport and low energy extraction are the major reasons for this cost reduction.

For in situ operations, supply costs have also been reduced through continuous improvement and innovation, although not to the same extent as in the surface-mining operations. Continuous improvement in CSS operations, the maturation of horizontal well technology and the development of the SAGD recovery technique are the major features that have facilitated this cost reduction. Current supply costs for CSS are estimated to be in the $10-$16 per barrel range, while those for SAGD are estimated to be $8-$14 per barrel. Costs for both methods are highly dependent on the quality of the reservoir.

Both integrated mining projects and thermal in situ projects use substantial amounts of natural gas as a fuel source in their operations. Thus, the price of natural gas is an important determinant of the level of profitability for these projects. The cost of condensate for blending of bitumen is also an important consideration.

In regard to primary recovery, the development of extended-reach and multi-leg horizontal wells facilitated the economic recovery of bitumen in the Wabasca region. In the Cold Lake region, the adoption of the progressive cavity pump in vertical well bores reduced the cost of production. Estimated supply costs for Wabasca are $7-$10 per barrel, compared to $10-$13 per barrel for Cold Lake.

The new royalty and fiscal regime is considered to be a positive and enabling feature, in that investors and developers are ensured of equal and predictable royalty and taxation treatment for all oil sands projects.

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b) Masson, R. and B. Remillard. "Alberta's New Oil Sands Royalty System." Alberta Department of Energy, May 1996.

c) Mitchell, R. *et al.* "Alberta Oil Sands: Update on the Generic Royalty Regime," Alberta Department of Energy, May 1998.

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Fisher, Larry and Louise Gill. "Supply Costs and Economic Potential for the Steam Assisted Gravity Drainage Process". CERI, Study No. 91, September 1999.

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CRUDE OIL SUPPLY

6.1 Introduction

This chapter focuses on the projections of oil supply derived from Canada's oil sands, divided into two categories reflecting the method of recovery. "Oil sands mining" includes all production derived from surface mining operations while "oil sands in situ" includes all production derived from in situ operations, including primary recovery projects. Supply projections are also expressed in terms of net available crude oil supply, a term which refers to the volumes of crude oil available to the market after upgrading and blending are taken into account. In addition, brief descriptions of the more important active projects as well as currently planned projects are provided.

6.2 Supply Projections

6.2.1 Methodology

The Board's oil sands supply projections are based on discussions with industry combined with the Board's analysis and expertise. The development plans for mining, in situ and primary recovery projects are considered, as are plans for upgrading and pipeline expansion projects. In addition, a cash flow model, combined with supply cost analysis, is used to gauge the pace of development activity. The starting point for the development of the supply projections is the consideration of the current trends in activity and the momentum that has resulted from the relatively high crude oil prices experienced since late 1999.

The economic assumptions used in the supply projections are primarily those contained in the Board's Supply and Demand Report, including a US$18 per barrel price forecast for WTI. A summary of the economic assumptions are provided in Appendix A-3. The supply projections for conventional light crude oil, pentanes plus and conventional heavy crude oil are from Case 1 of the Supply and Demand Report, except that conventional heavy crude oil has been modified upwards reflecting higher than expected actual production.

In addition to the Base Case projections, which are based on a US$18 per barrel oil price, sensitivities at US$14 per barrel ($14 Sensitivity) and US$22 per barrel ($22 Sensitivity) were run to test the effect of price on supply.[1]

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[1] In the $14 and $22 Sensitivity, a WTI price of US$14 and US$22 (1997, real, constant) is assumed; other econometric assumptions remain the same as in the Base Case.

6.2.2 Oil Sands Mining

Oil sands mining production generally refers to synthetic crude oil or upgraded crude oil from integrated oil sands mining projects, but also includes production that is mining derived and marketed as a blended bitumen.

In 1999, crude oil derived from oil sands mining averaged over 51 500 m^3/d[1] or approximately 15 percent of the total Canadian crude oil production. By 2015, oil sands mining derived production is projected to reach 158 000 m^3/d (Figure 6.1).

The supply projection in the Base Case includes the expansion plans of the Syncrude and Suncor operations, as well as the announced development plans of the Athabasca Oil Sands Project by Shell and partners. Although the supply projection includes additional new projects, they are not specifically identified, as the scheduling and size of the proposed projects will no doubt change with changing economic conditions, and not all announced projects are likely to proceed. In addition to assessing the merits of individual projects, the results of an industry cash flow model[a] are used to predict the pace at which development might proceed. The various expansion and development plans are discussed in Section 6.4.1.

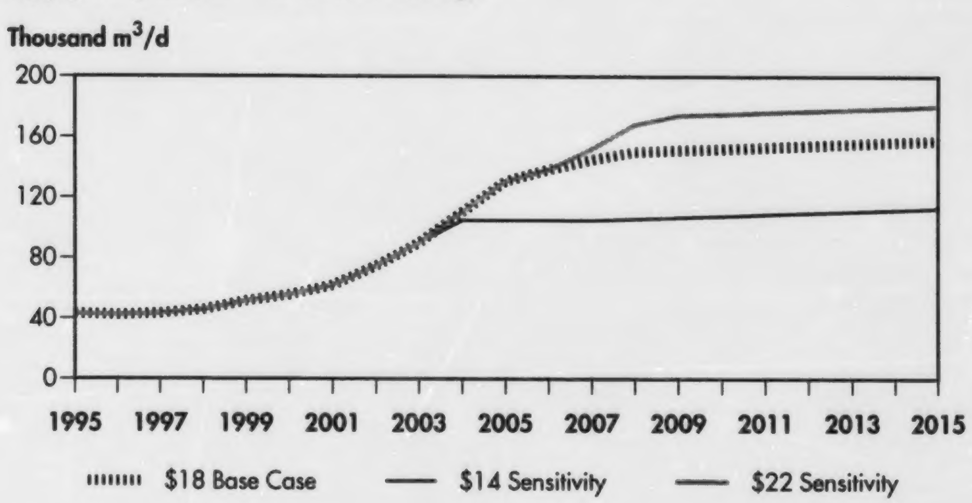
6.2.3 Price Sensitivities - Oil Sands Mining

In the $22 Sensitivity, the Syncrude, Suncor and Athabasca projects proceed as scheduled. As well, an additional 22 000 m^3/d of production is brought on by 2010, allocated to undefined projects that could include new large scale projects as well as additional expansions of existing projects. Production reaches over 180 000 m^3/d in 2015, which is about 14 percent higher than in the Base Case.

In the $14 Sensitivity, the actual price track used does not decline to US$14 from current prices until 2002. The economics at this price discourage any new development. In this sensitivity, the Syncrude, Suncor and Athabasca projects are assumed to be operating; however, new projects and

FIGURE 6.1

Supply Projections - Oil Sands Mining



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[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

most expansion plans have been postponed indefinitely. The projected production rate in 2015 is approximately 112 000 m³/d, which is 29 percent lower than in the Base Case.

6.2.4 Oil Sands In Situ

Oil sands in situ production generally refers to bitumen derived from in situ oil sands projects that is blended with condensate and moved to market as a blended bitumen, but may include some bitumen volumes that are fed into integrated mining/upgrading plants. The term "bitumen" is commonly used when referring to in situ production.

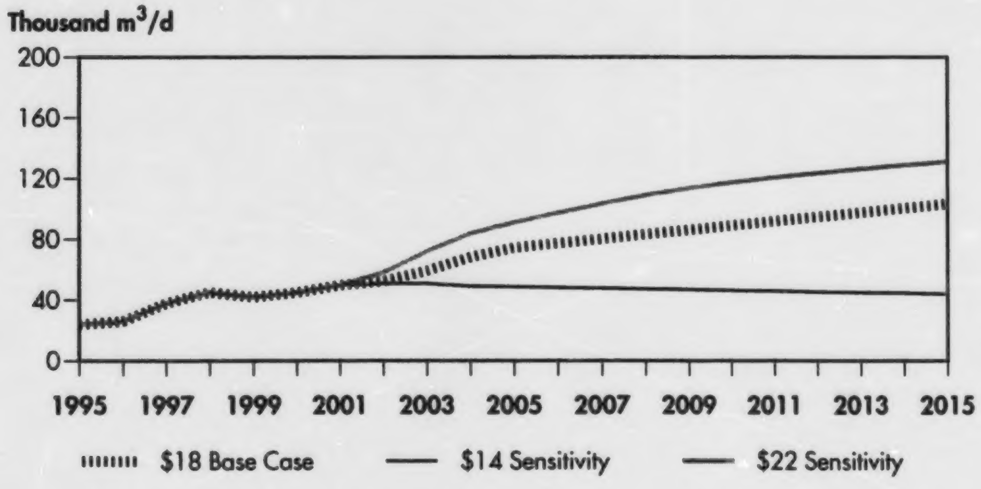
Similar to the development of the supply projections for mining projects, individual projects are assessed on their merits and given a relative ranking. In addition, the results of an industry cash flow model are used to assess the pace at which development might proceed. As a result, not all announced projects are specifically included in the supply projections, and the implementation of some projects is delayed. The early part of the projection period is more heavily influenced by projects that are currently being developed or are near commencement, while the cash flow model results have more weight in defining the longer term outlook.

Since the in situ projects are largely thermal projects that are based on steam stimulation, the price of natural gas is an important consideration, as is the cost and availability of diluent for blending and the differential between light and heavy crude oil.

Bitumen production averaged over 42 000 m³/d in 1999 (Figure 6.2). Thermal projects operated by Imperial and Canadian Natural Resources Ltd. (CNRL) in the Cold Lake/Primrose area account for most of the bitumen production to date, but there has also been significant production from the Lindbergh and Peace River areas. Primary production from the Cold Lake and Wabasca region is an important component of in situ production, accounting for 14 000 m³/d or 33 percent of total bitumen production. Some expansion of primary production from the Wabasca area is anticipated; however, the response is limited by the quality and quantity of the remaining resource base. Primary production in the Cold Lake area is expected to expand moderately, in accordance with the economics of this type of production.

FIGURE 6.2

Supply Projections - Oil Sands In Situ



There are currently over 40 new bitumen projects or expansion phases proposed. In the Base Case supply projections, bitumen production is expected to increase to 103 000 m^3/d by 2015 (Figure 6.2).[1]

6.2.5 Price Sensitivities - Oil Sands In Situ

In the $22 Sensitivity, the production of bitumen increases significantly, reaching 131 000 m^3/d by 2015. This is 30 percent higher than in the Base Case.

In the $14 Sensitivity, the netbacks to the producer are not sufficient to encourage any additional development; in fact, after 2001 the projected supply decreases by about one percent per year. By 2015 bitumen production in the $14 Sensitivity is about 44 000 m^3/d or less than half of the production in the Base Case.

6.2.6 Pentanes Plus Supply

Although some pentanes plus is derived from field condensate, the bulk of the supply is derived from the processing of natural gas. The projection of pentanes plus supply is therefore directly tied to the natural gas supply projections. It is included in this report because pentanes plus are used primarily as a diluent to blend with heavy crude oil and bitumen to reduce density and viscosity in order to meet pipeline specifications.

The supply projections for pentanes plus are taken directly from the Supply and Demand Report, but modified to reflect actual production. In the Base Case, the supply of pentanes plus is projected to gradually increase from the current level of about 27 400 m^3/d in 1999 to about 35 000 m^3/d by 2015 (Figure 6.3a). These volumes do not include production from the East Coast of Canada.

In the $22 Sensitivity pentanes plus supply increases to about 36 000 m^3/d by 2015 (Figure 6.3b). In the $14 Sensitivity, supply increases slightly to over 29 000 m^3/d in 2001, and then gradually declines to under 24 000 m^3/d by 2015.

6.2.7 Diluent Requirement

The largest use of pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate its transportation to market by pipeline. Typically, raw bitumen requires approximately 40 percent of diluent to be added, while conventional heavy crude oil requires about seven percent. In 1997 there was a relative shortage of pentanes plus for use as diluent, and several steps were taken to alleviate the situation. A new viscosity standard was implemented on the Enbridge Pipeline Inc. system in early 1999, which reduced the diluent requirement by about 10 percent. As well, a condensate price equalization program was developed to encourage the inclusion of light crude oil streams into the diluent pool.

Two important determinants of the demand for diluent are the pace of development of bitumen projects and the amount of local upgrading installed. In the supply projections, most oil sands mining developments are assumed to include upgrading capacity, hence they require no net diluent. However, some mining and most in situ bitumen projects are assumed to include only partial or no upgrading and will therefore require significant additional diluent. The assumption is made that the Lloydminster Bi-Provincial Upgrader capacity is increased to 28 400 m^3/d by 2007.

It is estimated that about 4 000 m^3/d of pentanes plus is not currently available for use as a diluent. This amount includes the volumes that are used in miscible flood oil recovery projects, as refinery feedstock, or batched directly into light crude oil streams. It is assumed that these volumes would be available for use as diluent within the projection period.

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[1] The Base Case assumes an oil price of US$18 (1997) per barrel (WTI), a natural gas price of C$2.75 per gigajoule and a light/heavy differential of C$5 per barrel, all constant, real.

Figures 6.3a and 6.3b illustrate the balance between pentanes plus supply and net diluent requirement for the Base Case and the \$14 and \$22 Sensitivities. In the Base Case, a potential shortfall for pentanes plus first occurs in 2005, and reaches almost 5 000 m^3/d by 2015. Between 2005 and 2008 the short fall is less than 500 m^3/d.

In the \$22 Sensitivity, the net diluent requirement is about 11 000 m^3/d greater than in the Base Case by 2015. The potential shortfall first occurs in 2004, and reaches almost 15 000 m^3/d by 2015. In the \$14 Sensitivity, the net diluent requirement is about 24 000 m^3/d less than in the Base Case by 2015. As a result, there is no potential shortfall for pentanes plus during the projection period.

FIGURE 6.3A

Base Case - Pentanes Plus Supply vs. Net Diluent Requirement

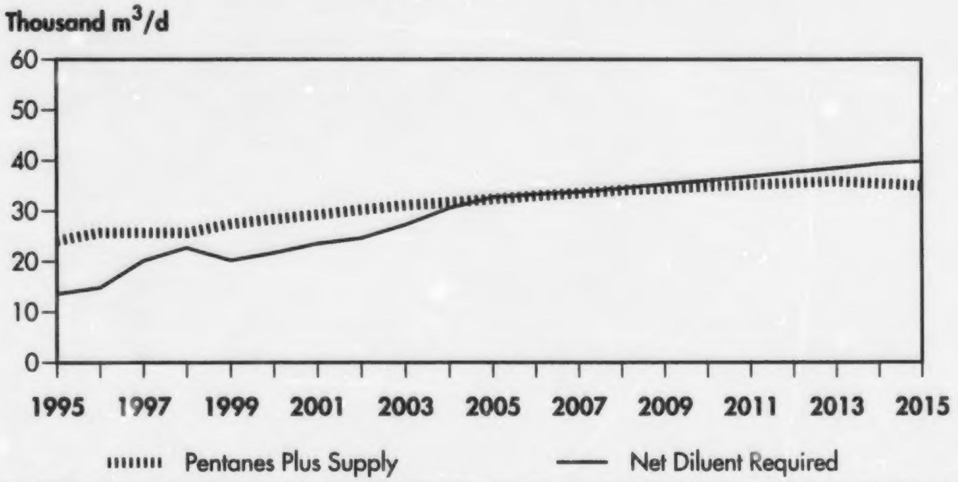
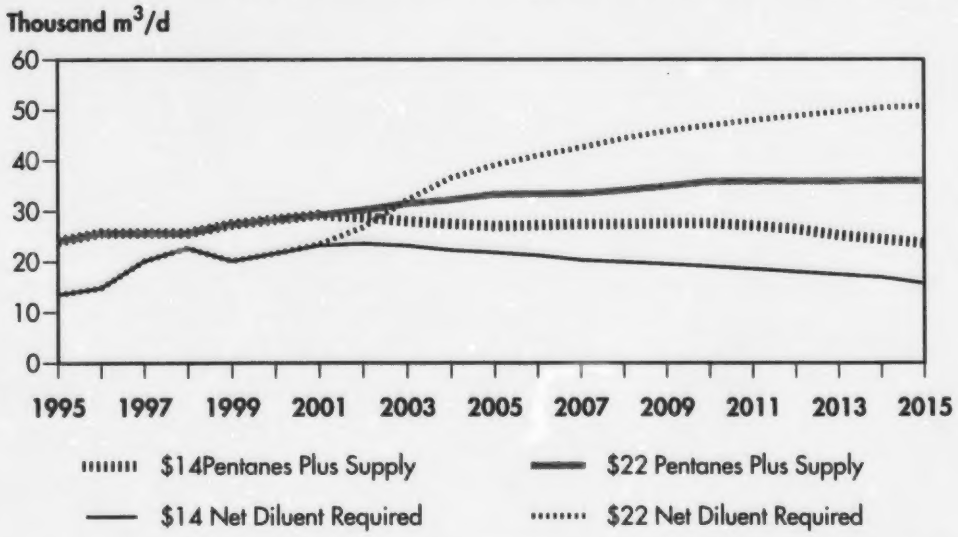


FIGURE 6.3B

\$14 and \$22 Sensitivity - Pentanes Plus Supply vs. Net Diluent Requirement



The potential shortfall of diluent in the Base Case and the $22 Sensitivity could be alleviated by adding local upgrading capacity, which could include partial upgrading or small scale field upgrading, if these latter technologies prove viable. Alternatively, some of the shortfall could be offset by using heated pipelines or by using other types of diluent, such as light crude oil, synthetic crude oil or naphtha, but these alternatives are not economically attractive. The potential shortage of pentanes plus for use as diluent poses a significant potential problem for the industry. The potential solutions all entail additional costs that could constrain heavy oil or oil sands development.

6.2.8 Net Available Supply - Crude Oil and Equivalent

"Net available supply" refers to the volumes of crude oil available to the market after taking upgrading and blending into account. Thus, the net available Canadian crude oil supply represents the total of WCSB conventional light crude, East Coast crude, synthetic crude oil, pentanes plus, blended heavy crude and blended bitumen, after local feedstock and diluent requirements have been met. It is assumed that some light or synthetic crude oil will be used as diluent. The projections of available supply take into account the diluent requirements for blending heavy oil and bitumen, recycled volumes of diluent, product losses during upgrading and volumes of pentanes plus not available to the downstream market.

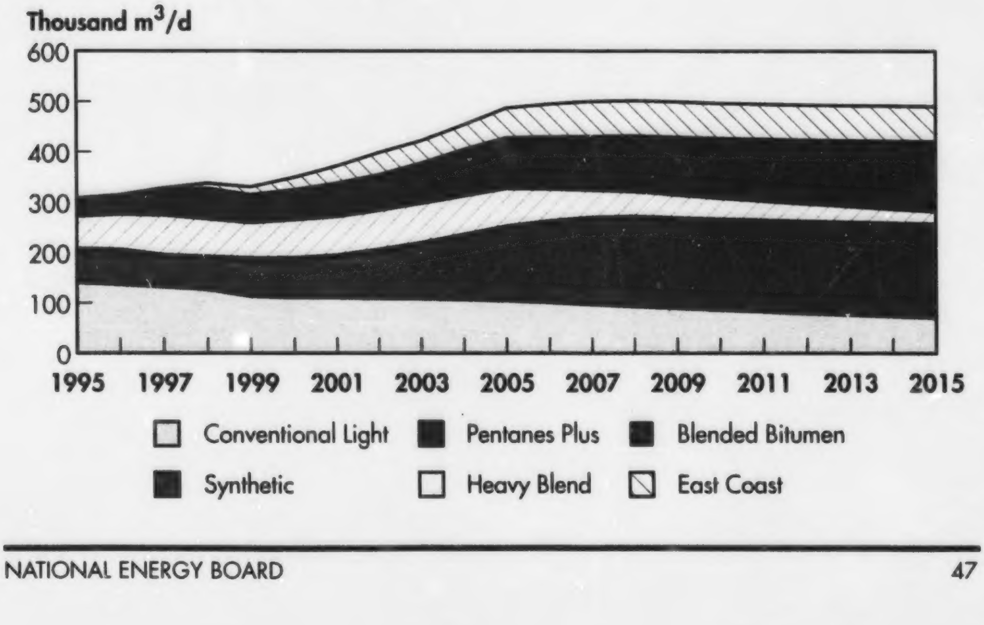
In 1999, WCSB conventional light crude oil made up about 34 percent, East Coast 5 percent, blended heavy oil 21 percent, pentanes plus 2 percent, synthetic crude oil 21 percent and blended bitumen almost 17 percent of the total net available supply of crude oil.

In the Base Case (Figure 6.4a), net available supply increases from 327 900 m^3/d in 1999 to a peak of 502 000 m^3/d in 2008, then gradually declines to about 490 000 m^3/d by 2015. By 2015, mainly due to natural decline, the share of WCSB conventional light and conventional heavy blend decreases to 15 percent and 5 percent, respectively, of the net available supply. Conversely, synthetic and blended bitumen production increases to about 38 percent and 28 percent, respectively, and East Coast production increases to 14 percent of total net available supply.

In the $22 Sensitivity (Figure 6.4b), the net available supply increases to almost 606 000 m^3/d in 2012 and then decreases slightly to 603 000 m^3/d by 2015. At the end of the projection period synthetic

FIGURE 6.4A

Net Available Supply - Base Case



crude oil makes up about 35 percent and blended bitumen about 30 percent of the total Canadian net available supply. WCSB conventional light represents only 13 percent and blended heavy oil only 6 percent by 2015. Similar to the 1999 Supply and Demand Report, the $22 Sensitivity includes production from the MacKenzie Delta-Beaufort Sea region starting in 2010, and reaching 25 000 m^3/d by 2012.

In the $14 Sensitivity (Figure 6.4c), the net available supply of crude oil decreases to about 314 000 m^3/d by 2015. Of this amount, synthetic crude oil encompasses about 45 percent and blended bitumen about 19 percent of the total net available supply by 2015. The amount of net conventional heavy blend available approaches zero by 2015 as most of the heavy blend is used locally as upgrader feedstock.

FIGURE 6.4B

Net Available Supply - $22 Sensitivity

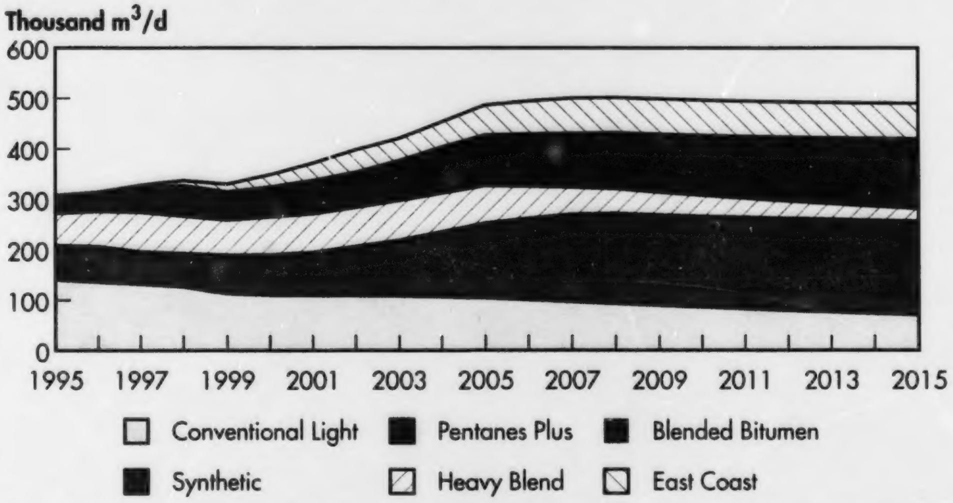
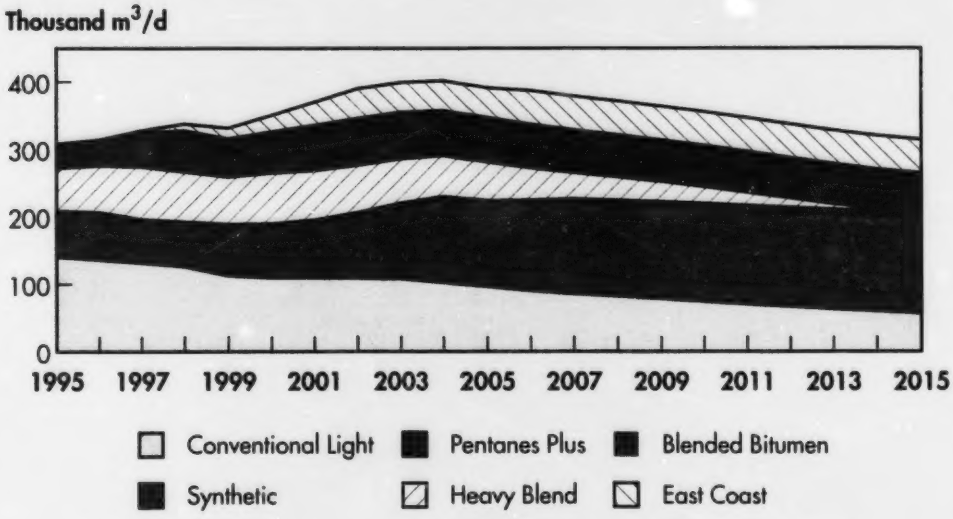


FIGURE 6.4C

Net Available Supply - $14 Sensitivity



6.3 Oil Sands Mining And In Situ Projects

In this section the major oil sands mining and in situ bitumen projects are briefly described. In most cases the production time table and some distinguishing characteristics will be featured. The information provided below is time sensitive as some project details may be subject to change and projects may be added or deleted.

6.4 Athabasca Deposit

6.4.1 Oil Sands Mining Projects

TABLE 6.1

Oil Sands Mining Projects

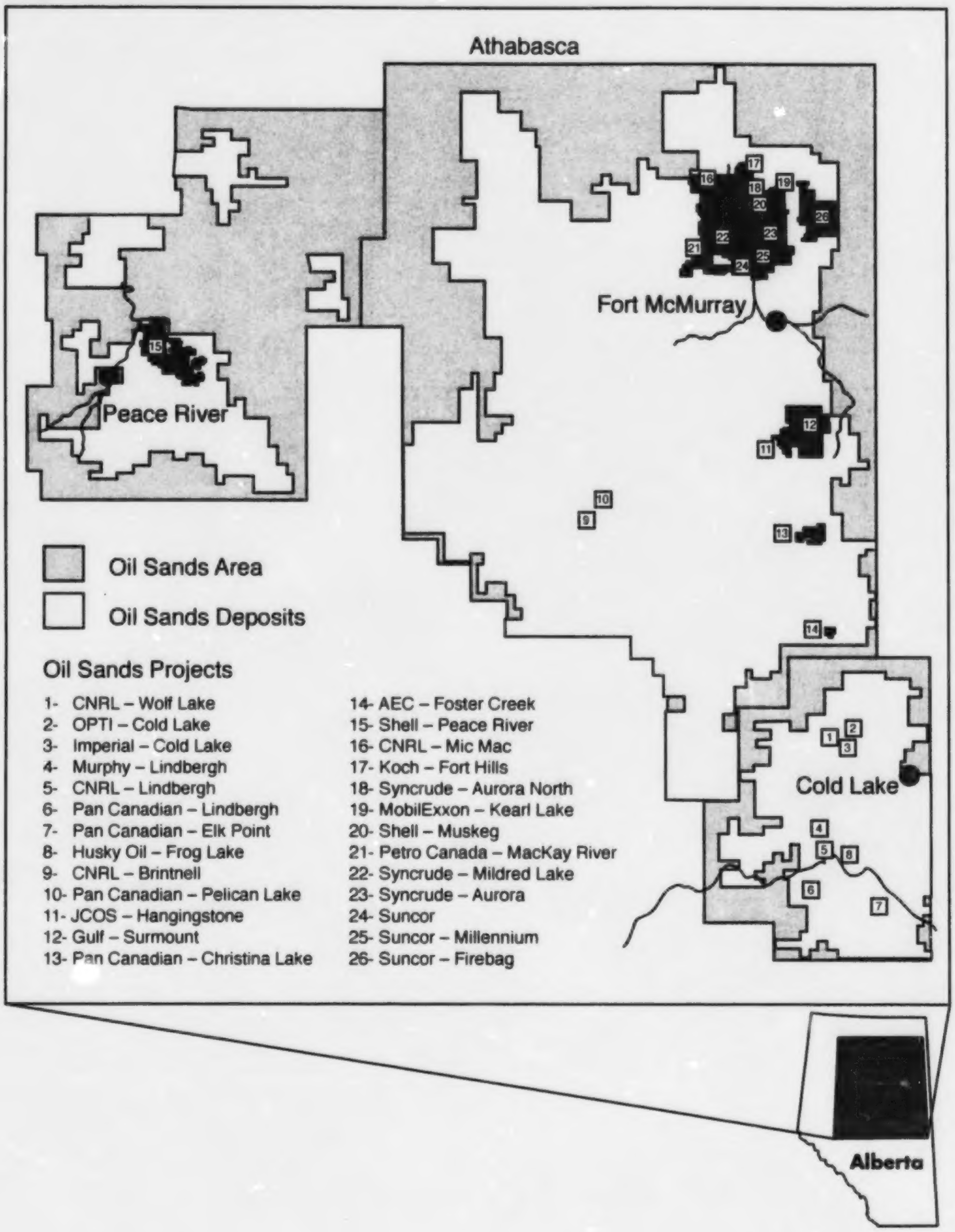
Project	Estimated Cost	Description
Suncor Energy Oil Sands Project Millennium	$600 million	Fixed Plant Expansion and Steepbank Mine - completed in 1999; expanded to 16 800 m^3/d.
	$190 million	Phase 1 - expand to 20 600 m^3/d in 2001.
	$2.0 billion	Phase 2 - expand to 35 000 m^3/d in 2002.
Syncrude Canada Ltd. Syncrude 21	$470 million	Stage 1: North Mine and Debottleneck 1 - construction from 1996-1999; expanded to 35 400 m^3/d.
	$1.0 billion	Stage 2: Aurora Train 1 and Debottleneck 2 - construction phase 1998-2001; expansion to 40 800 m^3/d.
	$3.0 billion	Stage 3: Aurora Train 2 and Upgrading Expansion 1 - construction from 2000-2004; expansion to 56 500 m^3/d.
	$2.3 billion	Stage 4: Aurora Train 3 and Upgrading Expansion 2 - construction from 2004-2008; expansion to 73 800 m^3/d.
Shell / Chevron / Western Athabasca Oil Sands	$1.8 billion	Muskeg River Mine will produce 24 600 m^3/d of bitumen starting in late 2002.
	$1.7 billion	Scotford Upgrader will be constructed next to Shell's existing Scotford Refinery.
TrueNorth / UTS Energy Fort Hills	$1.1 billion	Fort Hills project would produce approximately 15 000 m^3/d of bitumen from the initial mine by 2005.
ExxonMobil Corporation Kearl Oil Sands	$1.7 billion	Includes mining and extraction facilities for about 20 600 m^3/d of bitumen.
	$1.4 billion	New upgrader facilities (location unknown).

Millennium

In 1999, Suncor's synthetic crude oil production averaged 16 600 m^3/d. Project Millennium is expected to cost $2.2 billion and increase production to 35 000 m^3/d by 2002. Suncor has adopted a staged approach to managing expansion. The first phase is designed to improve processes and increase plant capacity by the year 2001. The second phase, the biggest phase of growth to date, includes further development of the Steepbank Mine, expansion of the extraction and upgrading plants, and increased requirements for steam, water and electricity.

FIGURE 6.5

Oil Sands Projects


Athabasca
Fort McMurray
Peace River
Cold Lake
Alberta
Oil Sands Area
Oil Sands Deposits
Oil Sands Projects
1- CNRL – Wolf Lake
2- OPTI – Cold Lake
3- Imperial – Cold Lake
4- Murphy – Lindbergh
5- CNRL – Lindbergh
6- Pan Canadian – Lindbergh
7- Pan Canadian – Elk Point
8- Husky Oil – Frog Lake
9- CNRL – Brintnell
10- Pan Canadian – Pelican Lake
11- JCOS – Hangingstone
12- Gulf – Surmount
13- Pan Canadian – Christina Lake
14- AEC – Foster Creek
15- Shell – Peace River
16- CNRL – Mic Mac
17- Koch – Fort Hills
18- Syncrude – Aurora North
19- MobilExxon – Kearl Lake
20- Shell – Muskeg
21- Petro Canada – MacKay River
22- Syncrude – Mildred Lake
23- Syncrude – Aurora
24- Suncor
25- Suncor – Millennium
26- Suncor – Firebag

Syncrude 21

Syncrude is Canada's largest single source of crude oil and the world's largest oil sands producer. The Syncrude Project is a joint venture operated by Syncrude Canada Ltd. and owned by AEC Oil Sands L.P., AEC Oil Sands Limited Partnership, Athabasca Oil Sands Investments Inc., Canadian Occidental Petroleum Ltd., Canadian Oil Sands Investments Inc., Gulf Canada Resources Ltd., Imperial Oil Resources, Mocal Energy Ltd., Murphy Oil Company Ltd. and Petro-Canada.

Syncrude 21 project will be designed and constructed from 1998 to 2007 and represents more than a \$6 billion investment. Once this four-staged expansion is complete production will be more than double the 1999 output of 35 400 m^3/d, reaching approximately 73 800 m^3/d in 2008.

Athabasca Oil Sands

This project is a joint venture, with Shell retaining a 60 percent interest and Chevron Canada Resources Limited and Western Oil Sands Inc. each holding a 20 percent interest. The mine will be constructed about 70 kilometres north of Fort McMurray. The Scotford Upgrader will be constructed next to Shell's existing Scotford Refinery near Edmonton. The upgrader will use hydrogen addition technology to process the bitumen from the Muskeg River Mine. Shell will also invest approximately \$400 million to modify its existing Scotford Refinery to utilize the new synthetic crude produced by the Scotford Upgrader.

As well, several companies will construct new facilities to serve the needs of the Athabasca Oil Sands Project under long term agreements. The Corridor Pipeline will transport the diluted bitumen from the mine to the upgrader (see Chapter 7.5). ATCO Power will build a 170 megawatt cogeneration facility to provide steam and electricity to meet the requirements of the mine, as well as additional electricity to the Alberta grid. ATCO Pipelines will build a pipeline to transport natural gas to the cogeneration facility.

Fort Hills

The Fort Hills Project is owned by TrueNorth Energy L.P. with a 78 percent share and UTS Energy holding the remaining 22 percent. The company estimates there are approximately 317 million cubic metres of mineable bitumen, providing reserves for 60 years of operation. A feasibility study will be completed by the end of 2000, with a commitment to a "go-no-go" decision on the development by early 2002 pending regulatory approval. A full scale upgrading facility is not planned at the Fort Hills site. TrueNorth may also pursue SAGD opportunities on the lease in areas where the overburden is too thick for mining.

Kearl Oil Sands

Kearl Oil Sands is an oil sands mining project proposed by ExxonMobil Corporation (ExxonMobil) on its Athabasca oil sands lease, located about 70 kilometres north of Fort McMurray. ExxonMobil believes the lease contains a high quality ore body with over 238 million cubic metres of recoverable bitumen in place. The project is currently on hold as ExxonMobil considers its options.

6.4.2 Other Mining Projects

The Mic Mac lease owned by CNRL has a production potential of 47 500 m^3/d. This lease contains an estimated 400 million cubic metres of oil sands reserves. The Mic Mac Project would likely be developed using both mining and in situ production methods with two-thirds of the production from mining and the remainder from SAGD.

SynEnCo Energy Inc. is proposing to build an oil sands mine and extraction plant 100 kilometres north of Fort McMurray. The plant is scheduled to begin operation in 2004, and has a rated production of 3 200 m^3/d. SynEnCo is proposing to use coal instead of natural gas to meet the project's fuel requirements.

6.4.3 In Situ Projects

Gulf Canada - Surmont Commercial Oil Sands

This project is located about 60 kilometres southeast of Fort McMurray. The oil sands formation is between 300 and 400 metres below the surface with thickness varying from zero to 60 metres. Each phase will have its own central facility consisting of steam generators, water recycling facilities, emulsion treating and storage tanks for diluent and blended bitumen ready for transport to market. Each phase of the development will be connected by pipeline to allow water, diluent and bitumen to be shipped between any of the locations.

TABLE 6.2

Athabasca In Situ Projects

Project	Estimated Cost	Description
Gulf Canada Resources Ltd. - Surmont (SAGD)	Phase 1 $300 million	Phase 1: 4 000 m^3/d by 2005. Developments in phased expansions of 4 000 m^3/d with an ultimate capacity of 16 000 m^3/d by 2013 given favourable market conditions.
PanCanadian Petroleum Limited - Christina Lake (SAGD)	Initial $400 million	Phase 1: 1 600 m^3/d by about 2002. Phase 2 and 3 both add 4 750 m^3/d, and are dependent on the success of Phase 1. If all three phases proceed production would be 11 100 m^3/d in 2007.
Petro-Canada MacKay River (SAGD)	$290 million	Expected to start producing in late 2002 reaching full production of 4 750 m^3/d in 6 to 8 months after start up.
Suncor Energy Oil Sands - Firebag (SAGD)	$450 million	Up to 5 500 m^3/d of bitumen in 2004. Plans to increase in situ production in stages to 22 000 m^3/d by the end of the decade.

The Surmont project was the subject of an EUB hearing into Gulf Canada's claim that the production of the natural gas reserves situated above their project was detrimental to oil sands recovery. The EUB ruled that the bitumen should be protected for development and ordered production to cease on 146 natural gas wells in the Surmont area.

PanCanadian - Christina Lake

PanCanadian Petroleum Limited will use the SAGD method at the Christina Lake project located approximately 170 kilometres south of Fort McMurray. This lease covers 35 sections which contains an estimated 475 million cubic metres of bitumen. Each of the three phases will have its own plant facility consisting of water treatment, steam generation, production separation, heat recovery, water de-oiling, water disposal and oil facilities. The project will begin steaming in the fall of 2001.

Petro-Canada - MacKay River

This project is located about two kilometres east of the Underground Test Facility which is now known as the Dover project. Due to the success of the Dover project, Petro-Canada believes it can successfully take the project directly to a commercial development without having a pilot project. At the MacKay River site there is approximately 125 metres of overburden. At this depth it is too deep for mining but too shallow for CSS. Petro-Canada must drill the vertical portion of the well at 45 degrees followed by the horizontal portion because of the shallow formation. MacKay River has a projected recovery of an estimated 37 to 48 million cubic metres of bitumen over a 25 year project life span.

Suncor - Firebag In Situ Oil Sands

Suncor will use the SAGD technique on its in situ oil sands leases located approximately 40 kilometres northeast of the company's oil sands plant. Suncor's combined oil sands leases have an in situ recovery potential of 800 million cubic metres of bitumen. The oil sands deposits in this area lie about 250 metres beneath the surface in the McMurray Formation. The raw production from Suncor's open-pit mine and from the proposed in situ project can be combined and sold directly to market or used as a feedstock in the oil sands upgrading facility. To give Suncor the capability to process the additional bitumen, the company plans to expand its upgrading facility by adding a vacuum tower complex by 2004 to coincide with production from the in situ facility.

6.4.4 Other Projects

Japan Canada Oil Sands Co., Ltd. will use SAGD at its Hangingstone property to produce up to 1 600 m^3/d by 2002. Northstar Energy Corporation is planning to increase production to 500 m^3/d at its Dover Project. Ormat Industries Ltd. (OPTI) is planning a 4 750 m^3/d in situ production operation southeast of Fort McMurray. AEC is operating a pilot project at Pelican Lake that is currently producing about 500 m^3/d. CNRL is considering a significant expansion of its primary bitumen production at Brintnell and Pelican Lake.

6.5 Cold Lake Deposit

6.5.1 In Situ Projects

TABLE 6.3

Cold Lake In Situ Projects

Project	Estimated Cost	Description
Imperial Oil Limited Cold Lake (CSS)	$630 million	Phases 11-13 (Mahkeses) will increase bitumen production by 4 750 m^3/d. Imperial is also considering phases 14-15 for future expansion plans.
Alberta Energy Company Foster Creek (SAGD)	$230 million	The first phase of 3 200 m^3/d of bitumen in 2002. Plans call for Foster Creek to be producing 16 000 m^3/d by 2007.
Canadian Natural Resources Ltd. Primrose and Wolf Lake (CSS & SAGD)	$130 million	With improvements to facilities and operating strategies it is expected to reach full capacity of 9 500 m^3/d by 2001. Two-phased plan, Phase 1 with completion in mid-2003 will add about 4 750 m^3/d. Phase 2, additional 4 750 m^3/d, will follow and take two years to complete.

Imperial - Cold Lake

Cold Lake is owned and operated by Imperial Oil Limited. Laboratory and field research projects over the past 30 years led to this phased commercial production project. Since the oil sands at Cold Lake are buried too deeply within the Clearwater Formation for surface mining, Imperial applies cyclic steam stimulation (CSS). Imperial currently operates phases one through ten of the Cold Lake facility. In 1999, Imperial's Cold Lake production averaged 20 700 m^3/d accounting for almost half of the bitumen produced in Alberta. Imperial has also planned a 220 megawatts steam cogeneration and electrical power facility at Cold Lake. Imperial expects to use about 45 percent of the power at the plant and will make the surplus power available to the Alberta Power Pool.

Alberta Energy Company (AEC) - Foster Creek

AEC's Foster Creek is located north of Wolf Lake in the middle of the Primrose Lake Air Weapons Range. AEC has been testing its SAGD extraction method for four years at its 300 m^3/d pilot project. The first phase will require 24 well pairs, a water treatment plant, an oil treatment unit, a testing centre and steam generators. Depending on market conditions and the success of the project, AEC has long range plans for Foster Creek to be producing 16 000 m^3/d by 2007.

CNRL - Primrose and Wolf Lake

CNRL's Primrose and Wolf Lake thermal heavy oil projects are located approximately 55 kilometres north of Bonnyville in northeastern Alberta. These properties, which CNRL purchased from BP Canada Energy Company (BP) in 1999, have been operating commercially since the 1980s. Currently, the production facilities are operating at about 50 percent of capacity.

CNRL will use both CSS and SAGD recovery techniques. CSS is used to target the Clearwater formations higher-clay content sands, while SAGD is used in the Grand Rapids zone which has fewer clay impurities. Their CSS process involves drilling horizontal wells rather than vertical or slant wells and injecting steam at a rate above the required reservoir parting pressure. The higher pressure will allow steam to penetrate farther into the oil sands allowing for fewer wells, reduced number of cycles and increased production. By drilling horizontally through the deposit, CNRL will be able to minimize both cost and surface disturbance by substituting a single well for between five and ten conventional wells.

6.5.2 Other Projects

There are several other projects in the Cold Lake area. AEC is operating a pilot project at Frog Lake. BlackRock Ventures Inc. has a pilot project at Cold Lake with potential for expansion up to 5 400 m^3/d by 2010. CNRL also has primary production at Beartrap. Murphy Oil Company Ltd. has primary production in the Lindbergh area with potential to more than double current production. CNRL also operates a SAGD pilot project at Burnt Lake which produces about 400 m^3/d. Petrovera Resources Limited operates primary bitumen production at Elk Point, Lindbergh, Frog Lake and Marwayne with significant expansion potential.

6.6 Peace River Deposit

Peace River

The Peace River project is owned by Shell Canada Limited. This site has an estimated 1.6 billion cubic metres of bitumen in place. Shell operated a pilot project at this site from 1979 to 1992 which was considered a technical success. More recently, Shell has used both CSS with multi-lateral wells and SAGD. Between 1997 and 1999, Shell produced about 1 000 m^3/d. Shell continues to assess the feasibility of a phased expansion.

6.7 Synergistic Development

Oil sands developers are taking advantage of new opportunities and technologies as well as synergies in their operations, in order to improve the economics and environmental performance of their projects. An example of this is cogeneration, which is the generation of hot water or steam and electric power at the same time from the same energy source, thereby yielding a highly efficient power plant.

TABLE 6.4

Current Cogeneration Facilities

Company	Location	Capacity (MW)	Description
TransAlta Utilities	Syncrude Mildred Lake	265	In operation since 1978.
TransAlta Utilities	Suncor Poplar Creek	360	Construction from 1999-2001. Phase 1 (220 MW) completed. Two steam turbines to be added in 2000 and 2001 to coincide with Suncor's Millennium project.
ATCO Power / Shell Canada / Air Products	Shell's Scotford Upgrader	150	Construction from 2000-2002.
CU Power Canada Ltd.	Shell's Muskeg River Mine	170	Construction from 2001-2002.
TransAlta Utilities	Imperial Cold Lake	220	Construction from 2000-2001, 45 percent of the power needed onsite, remainder goes to the Alberta power grid.

In a conventional power plant, waste heat in the form of turbine exhaust gases or condenser cooling water is rejected to the environment. With a cogeneration facility, a large portion of the waste heat is recovered and utilized by an adjacent facility which requires large amounts of heat. Cogeneration provides a cost-effective option for producing electricity, considering the increased efficiency of energy conversion and use. Additionally, cogeneration lowers emissions to the environment, carbon dioxide (CO$_2$) in particular, by capturing and recycling waste heat.

Table 6.4 lists the cogeneration facilities associated with integrated mining plants or in situ bitumen projects. The table includes projects currently in operation and those scheduled to be on stream by 2002.

The supply projections for the Base Case indicate that production of synthetic crude oil and bitumen will increase by about one and one-half times current levels by 2015. The integrated mining plants and thermal in situ projects use natural gas to generate process heat and electric power for their operations. Although improvements in energy efficiency are anticipated, the increase in natural gas demand by these operations will still be substantial.

An assessment was undertaken to examine the impact of the projected rapid growth of synthetic crude oil and bitumen production on natural gas and electrical power requirements, including an estimate of the electrical power that will be available to the Alberta power grid.

This assessment consisted of estimating the energy use and energy intensity, on a per unit of production basis, of current integrated mining/upgrading operations as well as in situ operations (both thermal and primary) and existing cogeneration plants. These estimates, together with certain assumptions, were applied to the Base Case supply projections.

The main components of this assessment are:

- current data on natural gas, electricity and internally-generated fuel usage for existing integrated mining/upgrading plants;
- consideration of the planned configuration of proposed new projects;
- energy efficiency data for typical gas turbines used in cogeneration facilities; and,

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[1] 35.3 cubic feet of gas equals approximately one cubic metre.

- the assumption that a two percent per year improvement in energy efficiency would be achieved, and for in situ bitumen, the assumption that one-third of incremental bitumen production will have associated cogeneration facilities.

The results of this assessment indicate that the external natural gas requirements related to integrated mining/upgrading operations more than double from current levels by 2008, reaching 0.38 bcf/d,[1] then decrease gradually to the end of the projection period (Figure 6.6a).

Natural gas demand for in situ bitumen production, including primary production, increases steadily, reaching 0.65 billion bcf/d by 2015 (Figure 6.6b).

FIGURE 6.6A

Daily Natural Gas Requirement - Integrated Mining/Upgrading Plants

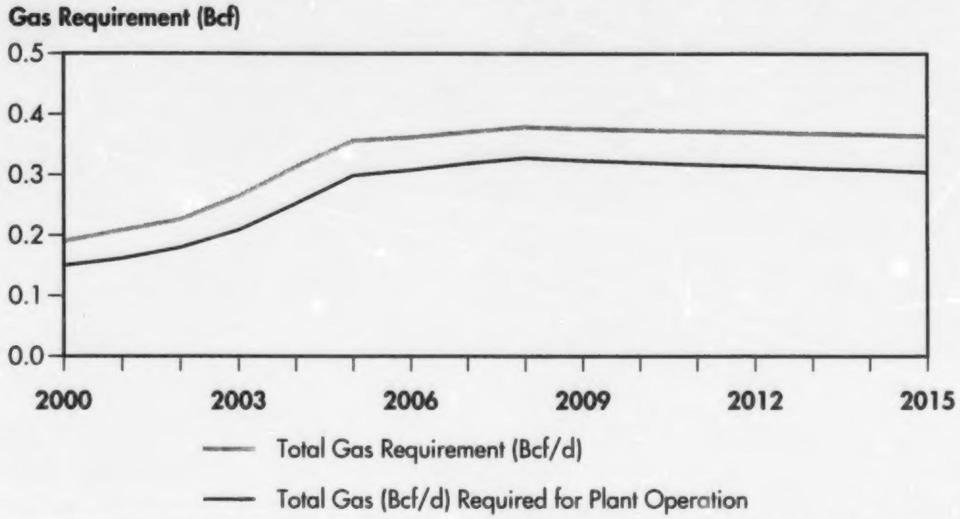


FIGURE 6.6B

Daily Natural Gas and Electrical Power Requirements In Situ Projects

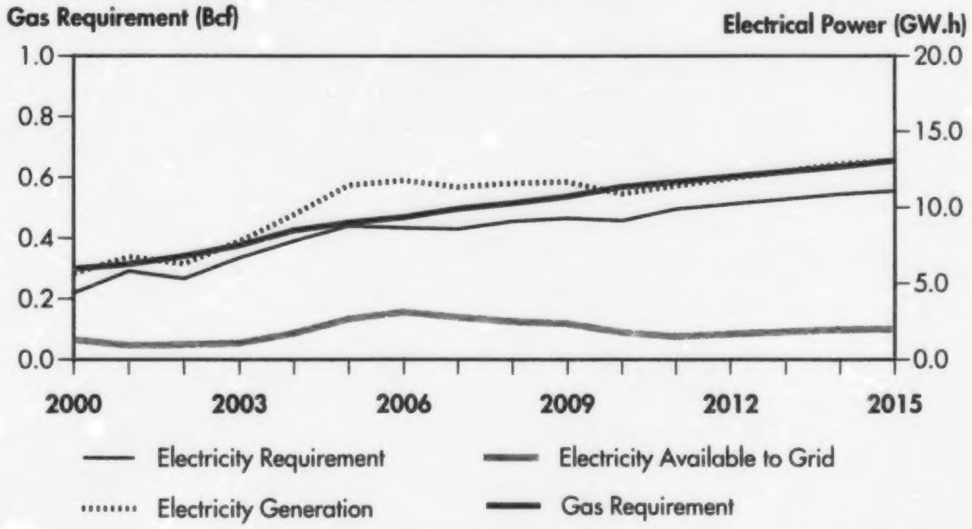
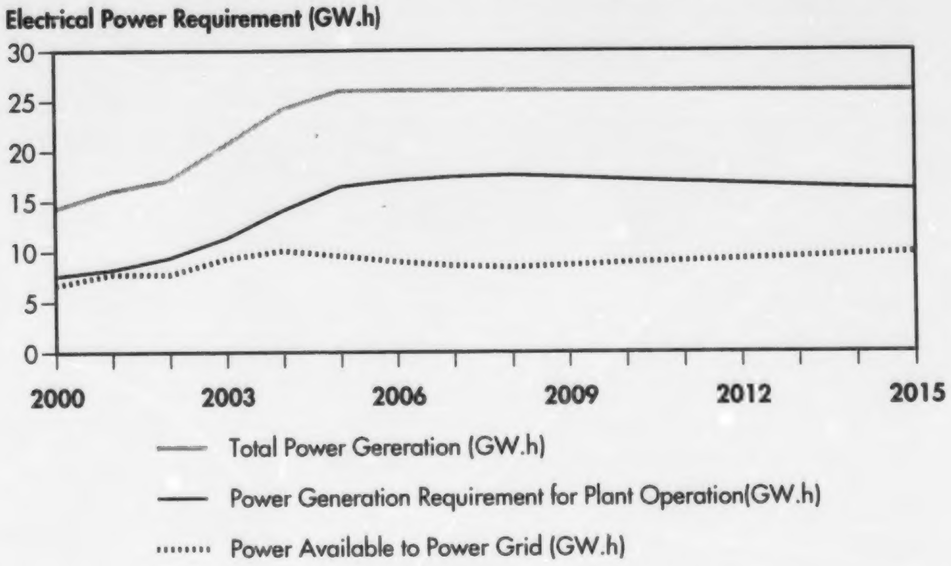


FIGURE 6.6C

Daily Electrical Power Requirement - Integrated Mining/Upgrading Plants



Total natural gas demand for mining and in situ operations is estimated to reach 0.98 bcf/d by 2015, compared to the current value of 0.46 bcf/d. By comparison, in 1999, Alberta natural gas production averaged 13.6 bcf/d.

The cogeneration facilities installed in association with the oil sands projects are estimated to have some excess capacity to generate power, that could be made available to the Alberta power grid. This excess daily capacity rises to about 13 GW.h by 2015 (Figure 6.6b and 6.6c). This excess capacity would generate about 4.8 TW.h annually, compared to current provincial annual generation of about 54 TW.h.

TransCanada Midstream Offgas Extraction Project

This is an agreement between Suncor and TransCanada Midstream to extract and separate natural gas liquids (NGL) and olefins from "off-gas," a byproduct of the oil sands upgrading process that is currently used as a fuel. The recovered liquids and olefins will be transported in batches via Suncor's Oil Sands Pipeline to TransCanada's Redwater, Alberta fractionation facility for further processing. The agreement will provide revenue to Suncor from the sale of products and reduce sulphur dioxide emissions at Suncor, as the off-gas is replaced as a fuel by cleaner burning natural gas. The plant, which is scheduled for commissioning in 2001, will extract ethane, propane, butane, condensate, ethylene, propylene and butylene from the off-gas. There is the potential to extract almost 3 000 m^3/d of NGLs and about 70 000 metric tonnes per year of polymer grade propylene from the off-gas.

Minerals and Precious Metals

A variety of valuable minerals, including precious metals, are known to exist within the oil sands deposits. A number of ventures have proposed methods of extracting these minerals from current tailings ponds or as a part of oil sands mining projects. While no operation of this type is currently operating, assessment and economic feasibility studies are being conducted.

Upgrading

The incremental supply cost of expansion at both Syncrude and Suncor is significantly lower than that of new grassroots projects due to the presence of existing upgraders and associated facilities. As another example, Shell is taking advantage of the synergies gained by building an upgrader next to its Scotford refinery.

6.8 Conclusion

The anticipated rapid growth in oil sands derived crude oil production is testament to the massive resource and economic potential of Canada's oil sands and the confidence shown by producers in the form of financial commitment and the development and advancement of enabling technologies.

In the Base Case, synthetic crude oil production is projected to increase nearly three-fold compared to current levels, reaching 158 000 m^3/d by 2015. Similarly, bitumen production is projected to increase by two and one-half times current production by 2015, reaching 104 000 m^3/d by 2015. Considering the declining trend in conventional heavy and conventional light crude oil production in Western Canada, oil sands production could be over 50 percent of total Canadian crude oil production by 2015.

A shortfall of pentanes plus for purposes of blending bitumen could occur as early as 2005, given the Base Case supply projections. This problem has the potential to constrain bitumen production, given that solutions currently available represent a significant added expense for producers.

The net available supply of Canadian crude oil, in the Base Case, rises to 502 000 m^3/d in 2008, then gradually declines to about 490 000 m^3/d by 2015. In the $22 Sensitivity, the net available supply includes production from the Mackenzie Delta-Beaufort Sea region and reaches a peak of about 606 000 m^3/d before declining slightly by the end of the projection period. In the $14 Sensitivity, the net available supply decreases to 314 000 m^3/d by 2015, or about 5 percent below current levels.

An assessment of natural gas requirements and electrical power generation related to oil sands development indicated that gas requirements would double to nearly 1 bcf/d by 2015, and that about 4.8 TW.h of generating capacity would be available to the Alberta power grid, also by 2015. This represents about 7 percent of Alberta's 1999 gas production and about 9 percent of its 1999 power generation capacity.

References

a) Oil and Gas Exploration and Extraction Estimation Model (OGEEE), Version 6.4, by CCH Consulting. This model forecasts activity based on historical relationships between several variables, such as, commodity prices, cash flow, resource potential, capital and operating costs, production rates as well as certain financial variables (inflation, interest and exchange rates).

Selected Background Literature

Athabasca Oil Sands Developers, "Progress in Canada's Oil Sands." June 2000.

CHAPTER SEVEN

PIPELINES

7.1 Introduction

This chapter presents a discussion of the location and capacity of the pipelines that transport crude oil in Canada and to the United States. Also included is a discussion on proposed pipeline projects that have been announced to transport increasing crude oil production.

7.2 Alberta Hubs

The various feeder pipelines that gather and transport blended bitumen and synthetic crude oil from northern Alberta converge at two main hubs, located at Edmonton and Hardisty (Figure 7.1). From these hubs, crude oil is shipped in segregated batches on trunklines that serve the various markets in Canada and the United States.

The Edmonton hub has approximately 900 000 cubic metres[1] of storage capacity, and receives various types of crude oil from numerous feeder pipelines. The crude oil is shipped from the Edmonton hub on two main trunklines. Enbridge Pipelines Inc. (Enbridge) is the major carrier of crude oil to eastern Canadian and U.S. markets, while the Trans Mountain Pipe Line Ltd. (Trans Mountain) system moves crude oil to the west coast. In many instances, light crude oil received from the feeders is co-mingled and shipped as a blend.

The Hardisty hub is located 220 kilometres southeast of Edmonton, and connects several feeder pipelines with the Express Pipeline Ltd. (Express) trunkline and the Enbridge system. It has a storage capacity of about 740 000 cubic metres.

With an estimated 190 000 m^3/d of synthetic crude oil and bitumen production proposed to come on stream before the year 2010, several new pipeline projects have either been recently completed, are in various stages of construction, or awaiting regulatory approval.

7.3 Feeder Pipelines

Alberta Oil Sands Pipeline

Alberta Oil Sands Pipeline (AOSPL), owned by AEC Pipelines, runs from the Syncrude plant in Fort McMurray to Edmonton (Figure 7.1), with a spur connection to Shell's Scotford refinery near Edmonton. Originally at a capacity of 37 800 m^3/d, AOSPL expanded in 1998 to 43 700 m^3/d.

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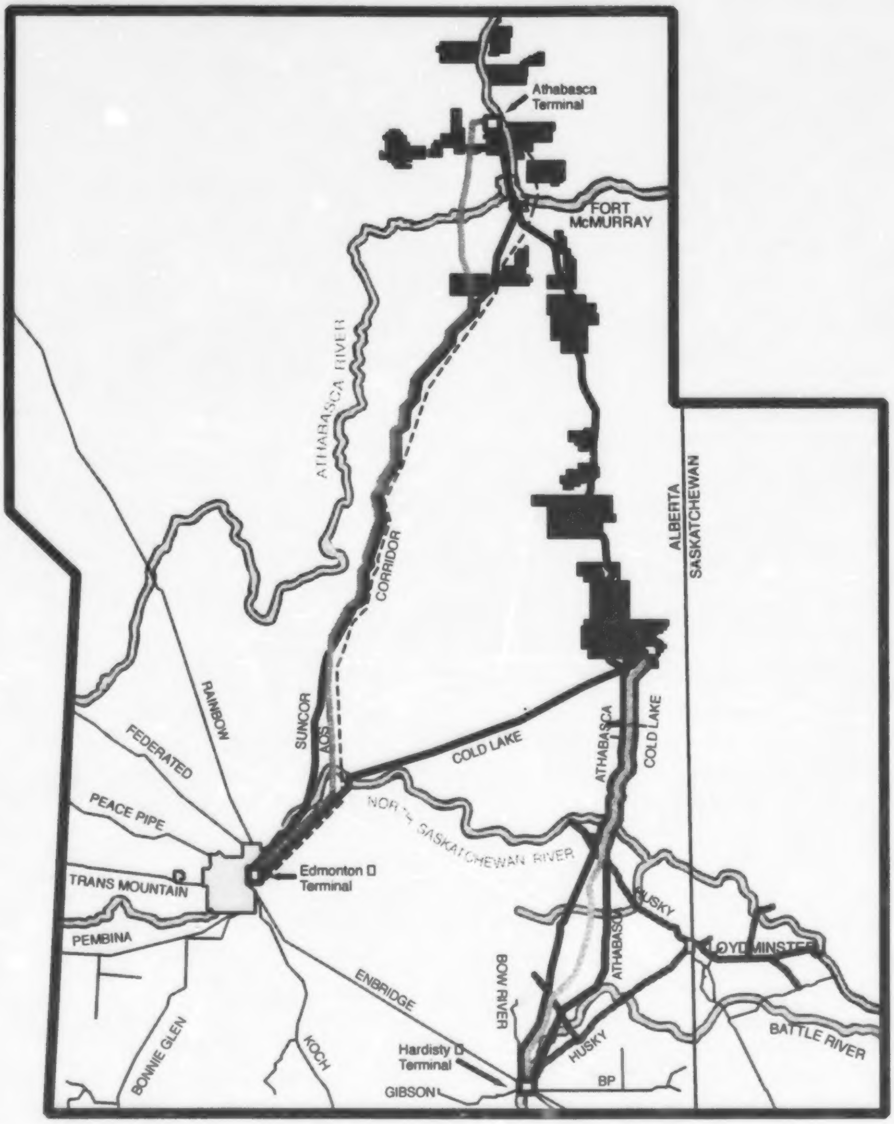
[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

FIGURE 7.1

Feeder Pipelines


Athabasca Terminal
FORT McMURRAY
ATHABASCA RIVER
CORRIDOR
ALBERTA
SASKATCHEWAN
RAINBOW
FEDERATED
PEACE PIPE
TRANS MOUNTAIN
PEMBINA
SUNCOR
AOS
COLD LAKE
ATHABASCA
COLD LAKE
NORTH SASKATCHEWAN RIVER
Edmonton Terminal
HUSKY
LLOYDMINSTER
ATHABASCA
BOW RIVER
ENBRIDGE
BONNIE GLEN
KOCH
Hardisty Terminal
GIBSON
HUSKY
BP
BATTLE RIVER

Athabasca Pipeline

The Athabasca Pipeline, owned by Enbridge, commenced operations in the spring of 1999. This 76 centimetre pipeline can ship about 15 900 m^3/d of synthetic crude oil and blended bitumen from Fort McMurray through Cold Lake and into the Enbridge and Koch Hardisty terminals.

The pipeline could be expanded to 90 500 m^3/d by adding pump stations. Expansion will only occur after transportation agreements have been executed with shippers.

Cold Lake Pipeline

The Cold Lake Pipeline System, owned by AEC Pipelines L.P., Koch Pipelines Canada L.P. and CNRL, has a capacity of 40 900 m^3/d. This partnership has entered into long term shipping contracts with Imperial, AEC, CNRL and Koch. The system consists of a 60 centimetre pipeline moving blended bitumen from the Cold Lake area to Edmonton and a 30 centimetre diluent return line.

Pelican Lake Pipeline

Pelican Lake Pipeline, owned by AEC, CNRL, PanCanadian and Chevron Canada, has a capacity of 23 800 m^3/d. It carries blended heavy crude oil from Pelican Lake to terminals in both Wabasca and Mitsue, and into the Rainbow pipeline for delivery to the Edmonton hub. Completed in June 1998, Pelican Lake pipeline began operations at 4 800 m^3/d.

ECHO Pipeline

ECHO Pipeline is owned by CNRL and Gibson Petroleum Company Ltd. The 150 kilometre pipeline transports heavy crude oil from the Elk Point area south of Cold Lake to the Gibson terminal at Hardisty. The 30 centimetre diameter pipeline is unique in that it is insulated and has a mid-point booster/heater that preserves the heat contained in the crude oil, allowing it to be transported without the addition of condensate at the originating point. Blending of condensate with the crude oil occurs at Gibson's Hardisty terminal to meet shipper requirements and downstream Enbridge and Express pipeline specifications. The ECHO pipeline has a capacity of 8 600 m^3/d.

Husky Pipelines

Husky Pipelines, owned by Husky Oil, has several gathering pipelines that transport blended heavy crude oil production from Cold Lake and west central Saskatchewan to the Husky upgrading and refining facilities at Lloydminster, Alberta or to the Hardisty hub.

Manito Pipeline

Manito Pipeline is owned by Murphy Oil Company Ltd. and Van Horne Pipeline Limited. It consists of a 25 centimetre pipeline moving blended heavy crude oil south to the Kerrobert, Saskatchewan terminal for injection into the Enbridge system, with a small ten centimetre pipeline moving condensate northbound to Dulwich, Saskatchewan.

Rangeland Pipeline

Rangeland Pipeline, owned by BP, is supplied by the Federated, Pembina, and Imperial pipelines. Rangeland has a Sundre to Rimbey mainline connecting to the Imperial pipeline, which runs north to Imperial's Edmonton refinery. Rangeland also runs south from Sundre to the U.S. border at Montana, where it connects to the Conoco pipeline which supplies Billings, Montana and Salt Lake City, Utah markets. Rangeland delivers mainly light crude oil and pentanes plus, but also ships Cold Lake blend crude oil from the Imperial pipeline for delivery into Billings. With a capacity of 16 500 m^3/d, the Conoco pipeline delivers crude oil into the Great Falls, Montana and Billings markets. At Cutbank, Montana the Conoco system intersects with the Front Range pipeline, which carries Bow River crude oil from the Milk River pipeline.

Crude oil produced in Wyoming is also carried on the Conoco and ExxonMobil pipelines. However, as a result of the natural decline in local production over the last five to seven years, only half of the 11 600 m^3/d capacity has been utilized to serve the Billings market.

Conoco also has a pipeline running from Guernsey, Wyoming to Denver, Colorado supplying up to 12 700 m^3/d of crude oil to the Frontier refinery in Cheyenne, Wyoming, and up to 9 500 m^3/d of crude oil to the Conoco and Ultramar Diamond Shamrock refineries in the Denver area.

Bow River Pipeline

The Bow River Pipeline, owned by Koch Pipelines Canada LP, runs south from Hay River, Alberta to the Murphy Milk River pipeline, which is connected to the Front Range Pipeline, where it serves the Billings and Salt Lake City markets. It has a capacity of 15 900 m^3/d and ships medium and heavy crude oil. The Bow River Pipeline also runs north from Hay River to the Hardisty hub.

Koch is contemplating reversing one of its three northbound pipelines to ship heavy crude oil south into the Billings market. Depending on the crude oil type, the reversed pipeline would have a capacity of 4 000 to 4 800 m^3/d. The earliest startup date would be the first quarter of 2001 to accommodate the asphalt season.

Milk River Pipeline

The Milk River Pipeline, owned by Murphy Oil Company Ltd., delivers crude oil mainly from the Bow River pipeline and the Manyberries pipeline into the Conoco system by way of the Front Range Pipeline in northern Montana. Milk River has a capacity of about 15 900 m^3/d.

Wascana Pipeline

The Wascana Pipeline, owned by Murphy Oil Company Ltd., has a capacity of 7 900 m^3/d. It runs from the Enbridge system at Regina, Saskatchewan to the United States border in eastern Montana where it connects to the Equilon pipeline system. The Equilon pipeline is connected to the Butte system, which delivers crude oil into Guernsey or Casper, Wyoming through the Belle Fourche Pipeline. Crude oil moved on Wascana can ultimately be delivered to the Salt Lake City area, or east to the Wood River region via the Platte pipeline.

The Equilon and Butte pipelines each have a capacity of approximately 17 500 m^3/d, and supply both Canadian and U.S. domestic crude oil to the Guernsey and Casper hubs.

7.4 Trunklines

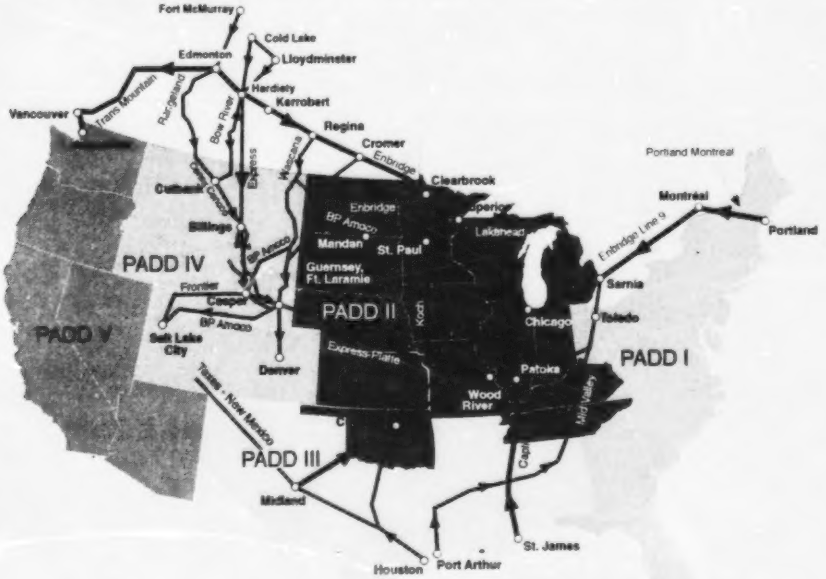
Enbridge Pipelines Inc.

Enbridge Pipelines Inc., owned by Enbridge Inc., has a total capacity of approximately 350 000 m^3/d. Enbridge is the primary transporter of crude oil from western Canada to Ontario and the United States (Figure 7.2). It receives crude oil at Edmonton and Hardisty, Alberta; Kerrobert and Regina, Saskatchewan; and Cromer, Manitoba. Enbridge serves the major refineries in Ontario and the Great Lakes region of the U.S. through the Lakehead pipeline system. This region is the largest market for all types of Canadian crude oil.

Enbridge also ships refined petroleum products from Edmonton to Saskatchewan and Manitoba, and transports natural gas liquids from Edmonton, Kerrobert, and Cromer to Sarnia, Ontario as well as various locations in the U.S. midwest. It has four parallel pipelines running from Edmonton to Hardisty and into the U.S. midwest. Enbridge serves the U.S. Rocky Mountain area indirectly via its connections to Express pipeline at Hardisty and the Wascana system at Regina.

FIGURE 7.2

Major Canadian and U.S. Crude Oil Pipelines and Markets


Fort McMurray
Cold Lake
Edmonton
Lloydminster
Hardisty
Kerrobert
Vancouver
Trans Mountain
Rangeland
Bow River
Express
Wascana
Regina
Cromer
Enbridge
Clearbrook
Portland Montreal
Montreal
Portland
Cutbank
Billings
Enbridge
BP Amoco
Mandan
St. Paul
Superior
Lakehead
Enbridge Line 9
Sarnia
PADD IV
BP Amoco
Guernsey,
Ft. Laramie
Frontier
Casper
PADD II
Koch
Chicago
Toledo
PADD V
BP Amoco
Salt Lake City
Denver
Express-Platte
PADD I
Patoka
Wood River
Mid Valley
Texas - New Mexico
PADD III
Capline
Midland
St. James
Houston
Port Arthur

The Lakehead system is 15.3 percent owned by Enbridge, and connects to the Enbridge pipeline at the Canada/U.S. border in southern Manitoba. The Lakehead pipeline delivers crude oil directly to the large Chicago, Illinois market, and north to Sarnia, Ontario. The Lakehead system also connects to other pipelines, including the 30 percent Enbridge owned Mustang Pipe Line Partners system, which delivers western Canadian crude oil into the Patoka and Wood River, Illinois hubs. In addition, it connects to the Minnesota pipeline, which ships crude oil to refineries at Twin Cities, Minnesota.

Enbridge experienced apportionment during most of the 1990s, reflecting substantial increases in heavy and synthetic crude oil production. As a result, Enbridge proposed three expansions. The first expansion (Terrace Phase I), completed in early 1999, added about 27 000 m^3/d of capacity.

Phase II and Phase III of the Terrace expansion project propose to further increase capacity on the Enbridge system. The Phase II expansion, proposed for the fourth quarter 2001, will provide incremental capacity of 6 300 m^3/d. Phase III, proposed for the fourth quarter 2002, will add a further 22 200 m^3/d of new capacity. It should be noted that the timing and capacity of the expansions are subject to shipper commitments.

If all phases proceed, the Terrace expansion project would provide 55 500 m^3/d of additional capacity on the Enbridge system.

Trans Mountain Pipe Line Ltd.

Trans Mountain is a subsidiary of BC Gas Inc., and has a total capacity of 39 300 m^3/d. Trans Mountain delivers crude oil from the Edmonton hub and Kamloops, B.C. to the Chevron refinery in Vancouver, B.C.. As well, it ships refined petroleum products to terminals in Vancouver and Kamloops from the Edmonton refineries. Trans Mountain also ships Canadian crude oil through its subsidiary pipeline at Sumas, Washington to Washington State refiners, as well as through its Westridge dock facility to other west coast and offshore refiners. Its export capacity is estimated to be 19 000 m³/d. Trans Mountain currently ships small volumes of synthetic crude oil.

Express Pipeline Ltd.

Express Pipeline, owned by AEC, is a 27 300 m³/d trunkline that commenced operations in April 1997. It runs from Hardisty to markets in Guernsey and Salt Lake City. Express also owns the Platte pipeline, which it connects to at Casper. At the Casper hub, Platte transports Canadian crude oil and U.S. domestic crude oil from the Conoco and ExxonMobil pipelines in Montana to the Wood River market. In Missouri, the Platte pipeline intersects with the ARCO system that runs from Cushing, Oklahoma to the Chicago market. Platte's terminals at Casper and Guernsey have a total storage capacity of about 254 000 cubic metres.

Express is proposing to serve two new markets. The first is Kansas, which will be supplied by the new Holdrege, Nebraska connection, which is expected to be in operation by December 2000. This is anticipated to take 1 600 m³/d of Express/Platte capacity, providing shippers with access to the Kansas refining market of over 46 000 m³/d. The second connection to Billings, Montana, should begin operations in the second quarter of 2001 and utilize 1 600 m³/d of pipeline capacity, providing shippers with access to 23 800 m³/d of refining capacity.

As well, Express is forecasting an expansion to its baseload capacity of about 7 900 m³/d in January 2002, adding another 9 500 m³/d in January 2004 bringing total capacity at Hardisty to about 44 400 m³/d.

7.5 New Pipelines

Figure 7-1 illustrates both the existing and proposed feeder pipelines. The proposed projects are described below.

Corridor Pipeline

The Corridor project, owned by Trans Mountain, will consist of three pipelines. The first pipeline will run from Shell's Muskeg River Mine near Fort McMurray to Shell's Scotford refinery near Edmonton, and will carry 34 100 m³/d of diluted bitumen. The second pipeline will be a 10 300 m³/d return pipeline for diluent. This grassroots system is scheduled to be completed in 2002.

The third pipeline will transport 23 000 m³/d of synthetic crude oil from the Scotford refinery to the Edmonton hub. It will include a return pipeline for 19 000 m³/d of supplementary feedstock. This is also expected to be completed in 2002.

Also committed to this project, according to Trans Mountain, is oil sands production from Syncrude, Suncor, Shell and JACOS. Trans Mountain also expects that oil sands output from the Petro-Canada, Koch and Gulf projects will utilize this pipeline.

Cold Lake Pipeline

The existing Cold Lake Pipeline System which transports crude oil to Edmonton will be expanded with the construction of a new 60 centimetre pipeline to transport heavy oil from the Cold Lake area to Hardisty where it will connect with the Express Pipeline System, Koch Hardisty terminal and other facilities. This new pipeline, owned by AEC Pipelines L.P., Koch Pipelines Canada L.P. and

CNRL, will have an initial capacity of 31 750 m^3/d and is expected to be on stream in January 2002. In addition, the system will be extended north to AEC's Foster Creek SAGD project.

7.6 Conclusion

With the completion of projects described in this chapter there will be a substantial increase in feeder pipeline capacity to transport synthetic crude oil and blended bitumen into the Edmonton and Hardisty hubs. Trunkline capacity to move crude oil out of Alberta to the various markets will increase by 45 900 m^3/d by January 2004, if all announced proposals proceed.

Based on the estimated production of synthetic crude oil and bitumen over the next 15 years, it is expected that additional trunkline capacity will be added. Proposals have been announced by Express and Enbridge to serve key markets in Ontario, PADD II and PADD IV (Table 7.1).

The pace of pipeline capacity expansion is dependent on market conditions, and it is difficult to precisely predict the order and timing of these proposals. However, producers will attempt to penetrate the most economical markets which historically have been Ontario and the U.S. midwest, and more recently PADD IV.

TABLE 7.1

Announced Trunkline Capacity Expansions

	Capacity Increase	Completion
Enbridge	6 300 m^3/d	4Q/2001
Express	7 900 m^3/d	Jan/2002
Enbridge	22 200 m^3/d	4Q/2002
Express	9 500 m^3/d	Jan/2004

CHAPTER EIGHT

MARKETS

8.1 Introduction

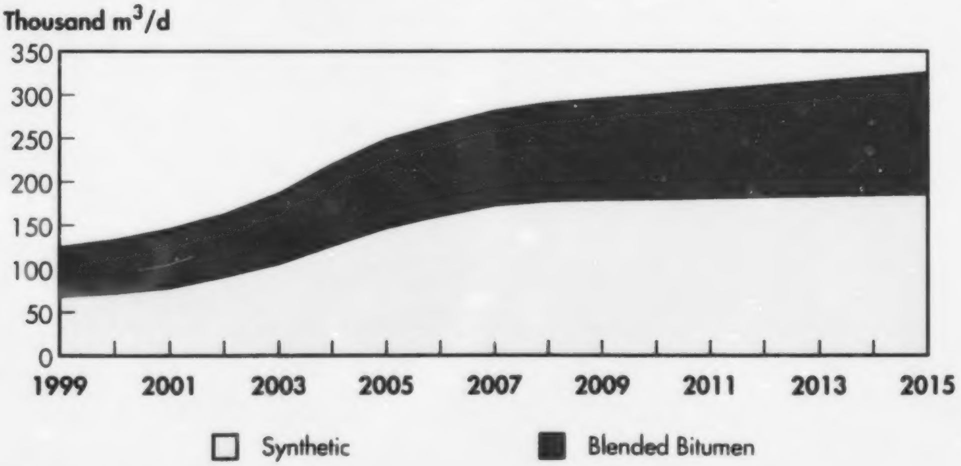
The production of Canadian synthetic crude oil and blended bitumen has grown significantly over the past few years, and this trend is expected to continue. As illustrated in Chapter 6 — Crude Oil Supply, there will be large increases in synthetic crude oil and blended bitumen production throughout the forecast period (Figure 8.1).[1]

It should be noted, however, that conventional light crude oil and equivalent is projected to decline throughout the forecast period. As well, conventional heavy crude oil output will begin to decline after 2003. Since the rising volumes of synthetic crude oil and blended bitumen could be expected to offset these declines, the net increases in synthetic crude oil and blended bitumen will be the focus of the discussion in this chapter (Figure 8.2).

Currently, three-quarters of Canada's synthetic crude oil and blended bitumen production is delivered to domestic refineries, all of which are operating at or close to capacity. Following the reversal of the Enbridge Sarnia-to-Montreal pipeline (Line 9), Canadian markets for both conventional and synthetic crude oil have declined, with most Ontario refiners now running significantly more imported light crude oil. Given this, the U.S. market, with its declining indigenous conventional crude oil supplies, will be a vital outlet for the additional production of synthetic crude oil and blended bitumen. It is likely that new U.S. markets will have to be developed.

FIGURE 8.1

Gross Synthetic and Blended Bitumen Production



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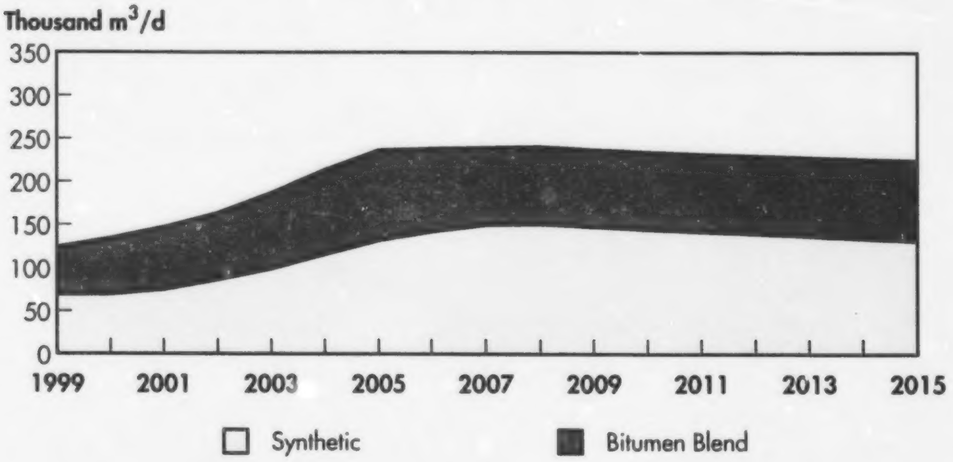
[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

FIGURE 8.2

Net Synthetic and Blended Bitumen Production



PADDs II and IV will be the primary growth markets for the rising quantities of synthetic crude oil and blended bitumen. However, as discussed later in this chapter, the level of market growth is dependent on several critical factors.

In this chapter, we will examine the various markets for synthetic crude oil and blended bitumen, including the current market share based on the Board's 1999 statistical data. The likelihood of producers finding markets for the additional synthetic crude oil and blended bitumen will also be discussed.

8.2 Refining/Upgrading

The United States is the largest potential market for the rising volumes of synthetic crude oil and blended bitumen. However, unless the quality of these non-conventional crude oils improves or investments are made to upgrade refineries, this market could become saturated.

Synthetic crude oil is a low sulphur feedstock with no residual fuel oil. It does not produce yields comparable to light sweet conventional crude oil, and therefore large quantities cannot be run in a traditional refinery. Synthetic crude oil is generally processed in a light crude oil cracking refinery, and typically represents less than thirty percent of the total crude oil slate. It also has poorer distillate qualities, resulting in an inferior yield of cracked products.

If refinery modifications are made, more synthetic crude oil could be absorbed in the U.S. marketplace. Light crude oil refineries are good candidates for conversion through the addition of hydrocracker facilities. Alternatively, producers could improve the quality of synthetic crude oil upstream. For example, by increasing the diesel cetane index to a minimum of 40 and improving the smoke point on distillate, marketability would be significantly enhanced. Additional hydrotreating would improve the quality of the distillate and gas oil fractions.

Bitumen is very heavy and viscous, and must be blended with diluent to transport it to market. It is expected that new refinery conversion capacity will have to be added to provide expanded markets for the increasing volumes of blended bitumen. Expansions to refineries currently processing blended bitumen and the conversion of light crude oil refineries could be considered. Upgrading at the source is another possibility. The likelihood of these options is highly dependent on economics and, specifically, the differential between light and heavy crude oil.

The price differential between light and heavy crude oil, as represented by the spread between the light Par crude oil at Edmonton and Lloydminster blend at Hardisty, is impacted by many different factors including seasonality and the available quantities of each grade of crude oil. As more blended bitumen production comes on stream, periods of oversupply in the traditional heavy oil markets are likely to develop. In these circumstances, the differential would be expected to widen, which in turn would stimulate additional upgrading facilities. In order to encourage new refinery residual conversion capacity in the U.S. Midwest, the differential would have to be maintained at C$6.00 per barrel or higher for a sustained period of time.

A further inducement to upgrade refinery capacity may occur as a result of a new Canadian government requirement that sets the amount of sulphur in motor gasoline to be no more than 150 ppm by July 2002, with further reduction to 30 ppm by 2005. This will make it necessary for refineries to invest in expanding their facilities, and many Canadian refiners are expected to make the change to 30 ppm in one step, in order to reduce the total capital cost. Most U.S. refiners will also have to make large investments in order to meet new environmental regulations imposed by the U.S. government. With these expenditures ahead of them, the question is whether refiners will take advantage of the opportunity to combine the cost of the enhancements needed to meet the environmental standards with the upgrading investments required to process a more diverse slate of crude oil.

8.3 Markets for Canadian Crude Oil

8.3.1 Western Canada

In 1999, western Canada was the largest market for synthetic crude oil. There are nine refineries in western Canada: Chevron, Co-op, Husky (2), Imperial, Moose Jaw Asphalt, Parkland, Petro-Canada and Shell. The combined refining capacity is about 88 800 m^3/d, of which thirty percent represents synthetic crude oil runs and three percent represents blended bitumen runs (Figure 8.3).

TABLE 8.1

Canadian Crude Oil Markets - 1999 (m^3/d)

Market	Refining Capacity	Refining Runs	Canadian Light[1]	Canadian Heavy	Canadian Synthetic Crude Oil	Canadian Blended Bitumen
W. Canada	88 800	83 016	39 841	13 333	27 302	2 540
E. Canada - all	216 200	199 206	49 365	14 444	8 571	3 175
E. Canada - Ontario	87 500	74 000	35 050	14 444	8 571	3 175
PADD I	269 000	255 556	18 722	5 183	1 011	25
PADD II	574 500	574 500	34 740	55 105	14 692	23 842
PADD III	1 198 900	1 197 816	255	0	0	0
PADD IV	85 800	84 247	12 235	20 639	2 119	2 287
PADD V	491 200	477 550	9 704	27	13	56

1 Includes condensate and pentanes plus

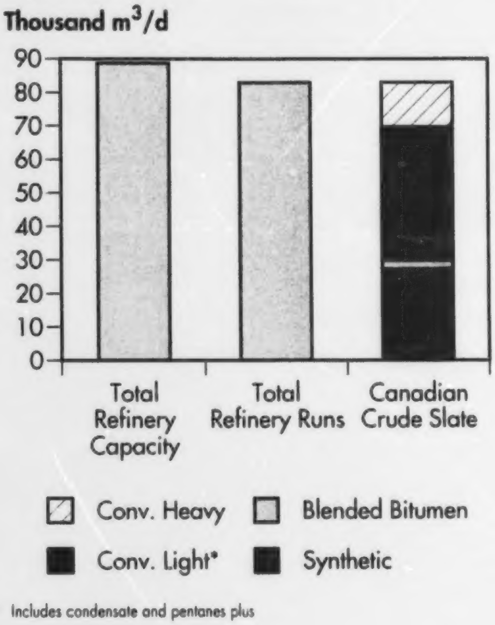
Source: Statistics Canada, National Energy Board and the U.S. Energy Information Administration

As mentioned previously in the refining/upgrading section, despite the large amount of synthetic crude oil available, many refineries cannot process more than about thirty percent of their crude slate as synthetic crude oil, due to quality issues. However, there are relatively low transportation costs associated with acquiring synthetic crude oil close to home. With low delivery costs, the ongoing decline in conventional light crude oil production, and evolving technologies for upgrading synthetic crude oil, producers can expect to capture a larger share of the western Canadian market, provided the quality issues are addressed.

Blended bitumen currently represents only three percent of the crude slate of the nine western Canadian refineries but has the potential to displace some conventional heavy crude oil in this market. However, significant upgrades would have to be made. Expansions to existing refineries could be undertaken or, if bitumen production were partially upgraded in the field, it could displace some conventional heavy crude oil.

FIGURE 8.3

Western Canada Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

Still, conventional heavy crude oil is favored because it yields a higher quality asphalt. Given that adequate supplies of conventional heavy crude oil are available, it is unlikely that blended bitumen will displace it to any great degree by 2015.

8.3.2 Eastern Canada

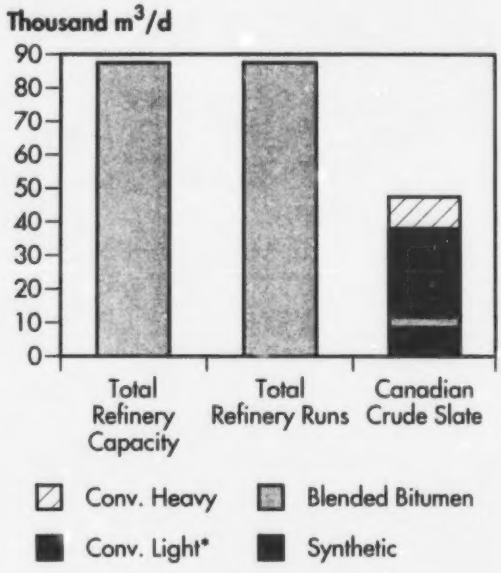
There are twelve refineries located in eastern Canada; however, synthetic crude oil and blended bitumen are transported only as far as the province of Ontario. There are six refineries in Ontario, with a combined refining capacity of 87 500 m^3/d (Figure 8.4). These refineries are owned by Imperial (2), Nova, Petro-Canada, Shell and Sunoco.

Ontario refiners, in aggregate, currently process a slate of 12 percent synthetic crude oil and four percent blended bitumen. In 1999, over 62 percent of refinery runs in Ontario were conventional light crude oil; 23 percent consisted of imported light crude oil. The Board expects that the percentage of imported crude oil will increase above the 1999 level reflecting the impact of the reversal of the Enbridge Sarnia-to-Montreal pipeline (Line 9).

There is some potential for synthetic crude oil to find a larger market share in Ontario. There was once a concern that, with the capital investment required to upgrade the plants to meet the new sulphur regulations for motor gasoline, as many as three eastern Canadian refineries would close. However, these refineries are all presently running close to or at capacity, and this is expected to continue. As well, with the new technologies being developed to reduce sulphur levels in gasoline, it is now believed that refiners will invest the capital required to upgrade their facilities in response to the environmental regulations. During the planning process for these investments, refiners could

FIGURE 8.4

Ontario Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

consider increasing their takes of synthetic crude oil. It is unlikely, however, that markets for blended bitumen will increase to any significant extent.

8.3.3 United States

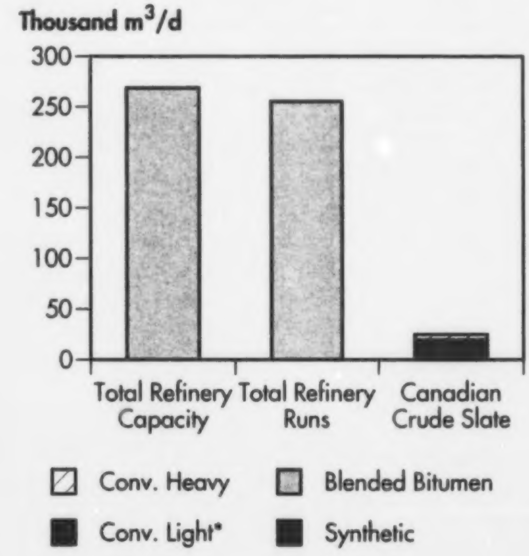
The United States market is divided geographically into five Petroleum Administration for Defence Districts — "PADDs" (Figure 7.2).

Companies wishing to export Canadian crude oil must first obtain authorization from the Board. From September 1973 to June 1985, Canada imposed controls on oil exports to reflect the requirements of the domestic price control regime and to address international oil market developments. All oil exports required a licence, issued by the Board, imposing volume, price and other restrictions on the terms of export contracts. Export charges were levied to make up the difference between controlled domestic prices and those available in export markets.

Deregulation in 1985 marked the end of the Board determining the prices of exported oil. The Board now issues, pursuant to an application, short-term export orders, which have no restrictions on volume or price. While exporters may apply to the Board for a long-term licence, all exports today are under short-term non-restrictive orders. In fact, since deregulation, the Board has not received an application for a long-term licence. The Board monitors export volumes and prices to ensure its awareness of events in the oil market. Based on these observations, the following sections discuss the Board's view of potential export markets for Canadian unconventional crude oil.

FIGURE 8.5

PADD I Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

PADD I

PADD I has 12 major refineries: American, BP Amoco, Coastal, Motiva, Pennzoil, Sunoco (2), Tosco (2), United, Valero and Young. They have a combined refining capacity of approximately 269 000 m³/d, and currently run a slate of mainly foreign crude oil and some U.S. domestic crude oil (Figure 8.5). Over 190 000 m³/d of the

PADD I crude oil requirement is imported and, of that, Canada provided 24 941 m^3/d in 1999. A large portion of this is production from the east coast of Canada.

PADD I takes only a minor amount of Canadian synthetic crude oil at this time, and it is expected that PADD I will absorb only small additional amounts. Canadian synthetic crude oil competes with cheaper foreign crude oil in this market, and would have to be further upgraded upstream and significantly price-discounted in order to capture a larger market share.

Blended bitumen is less likely to find a home in this market, as few refineries currently have coking facilities. There has been some discussion, however, of coking facilities being installed in the next few years. Nevertheless, it is expected that PADD I refiners will continue to rely on conventional crude oil from Canadian and foreign sources as their main feedstock.

PADD II

The largest U.S. market for Canadian crude oil production is PADD II. It has a combined refining capacity of 574 500 m^3/d (Figure 8.6). In 1999, 93 percent of Canadian crude oil exports were delivered into PADD II, with 14 692 m^3/d of that being synthetic crude oil and 23 842 m^3/d blended bitumen. This market takes more synthetic crude oil and blended bitumen than the other four PADDs combined, and is the largest processor of blended bitumen among all Canadian and U.S. markets.

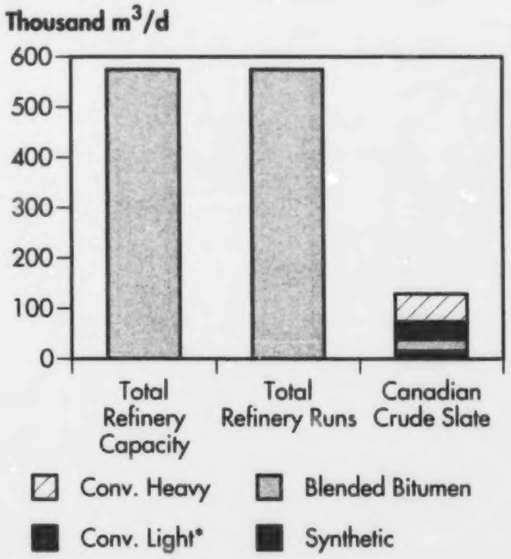
PADD II can be divided into four smaller regions: Chicago; Wood River and Southern PADD II; North Dakota/St. Paul/Superior; and Toledo/Detroit.

Chicago

Canadian producers ship crude oil into the Chicago market via the Enbridge/Lakehead pipeline system. The four refineries (BP Amoco, CITGO, Clark and ExxonMobil) located in this region have a combined capacity of approximately 132 500 m^3/d. These refineries also process crude oil shipped via mid-continent and Gulf Coast pipelines. Chicago is the largest PADD II regional market for Canadian crude oil, and has the largest potential to absorb additional production of Canadian synthetic crude oil and blended bitumen. In order for this to occur, however, the economics would have to provide an incentive for refiners to back out U.S. domestic or foreign crude oil to allow for a larger share of Canadian crude oil.

FIGURE 8.6

PADD II Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

In PADD II, particularly in Chicago, synthetic crude oil competes directly with Louisiana light sweet crude oil (LLS) which is of similar quality. Currently, LLS holds a larger market share of PADD II, as it is easier for refineries to process. However, if upgrades to synthetic crude oil were made upstream and it is price-discounted slightly, it may be able to obtain a greater portion of the Chicago market. In addition, the U.S. Gulf Coast is a major source of light sour conventional crude oil, projected to produce an incremental 111 000 m^3/d by 2002. This could put some competitive pressure on the market share of light Canadian crude oil, although it is likely that the bulk of this supply will be refined in PADD III.

Blended bitumen is not a largely used crude oil in the Chicago market. There is currently only 9 700 m^3/d of bitumen blend processed, while Canadian conventional heavy crude oil makes up 36 600 m^3/d of the Chicago area refinery slate. While these refineries currently have a sufficient supply of conventional crude oil, Canadian conventional heavy crude oil is expected to decline significantly throughout the forecast period. Nevertheless, it is unlikely that blended bitumen grades will capture more of the Chicago market until price differentials allow for upgrading.

Wood River and Southern PADD II

The Wood River and southern PADD II area is a potential growth market for synthetic crude oil and blended bitumen. There are three main refineries in Wood River: Clark, Equilon and Marathon Ashland. Canadian producers, via the Express/Platte pipeline system and the Enbridge/Lakehead/Mustang pipeline interconnect, easily access the Wood River area, which has a combined refining capacity of approximately 86 700 m^3/d. In addition, there are several other refineries in the vicinity of Wood River.

Due to the accessibility of this region, it has become a good market for Canadian conventional light and heavy crude oil. Though there is potential for increased market share, the issue facing synthetic crude oil producers in the Wood River market is the competition from PADD III crude oil. PADD III crude oil supplies are close to Wood River, and thus have lower transportation costs. The quality of synthetic crude oil will have to be improved upstream and price-discounted before it can make major strides in this market. However, it is expected that, with the decline in both Canadian and U.S. domestic supplies of light conventional crude oil, synthetic crude oil will eventually penetrate the Wood River area.

In the case of blended bitumen, very small volumes were run in 1998; however, according to the Board's data, no blended bitumen was processed in 1999. It is expected that the Wood River refiners will again take small amounts of blended bitumen, and producers will continue to penetrate this market.

North Dakota/St. Paul/Superior

The Northern PADD II area is served by the Enbridge/Lakehead system, with the Minnesota pipeline connecting it to the St. Paul, Minnesota/Superior, Wisconsin area. The BP Amoco pipeline connects to the North Dakota market. There are four main refineries (BP Amoco, Koch, Murphy and Marathon Ashland) with a combined refining capacity of almost 121 500 m^3/d. These four refineries receive over 75 percent of their crude requirements from Canada, and the three eastern-most plants process a significant amount of synthetic crude oil and blended bitumen.

There is little competition from foreign crude oil in this region. Synthetic crude oil competes with Canadian conventional crude oil and U.S. domestic crude oil, which is on a steady decline of about four percent per year and not easily delivered to this market.

In 1999, synthetic crude oil increased its market share in the St. Paul and Superior market by twelve percent relative to 1998. It is expected that synthetic crude oil demand will continue to grow, given the complexity of the refineries in this region.

This is also the case with blended bitumen. The bulk of the PADD II blended bitumen receipts are shipped to St. Paul and Superior. With the upgrading capabilities of some of the refineries in this region, blended bitumen will continue to have a large market share, and could potentially displace some conventional heavy crude oil imports.

Toledo/Detroit

The Enbridge/Lakehead pipeline delivers Canadian crude oil into the Toledo/Detroit area to four refineries. The combined capacity of the BP Amoco, Marathon Ashland (2) and Sun refineries is roughly 69 800 m^3/d. In 1999, almost 20 000 m^3/d of Canadian crude oil was processed.

Synthetic crude oil makes up about nine percent of the Canadian crude oil that is shipped to the Toledo/Detroit area. There could be a potential market for additional synthetic crude oil to be absorbed in this market, provided that the cost of U.S. domestic supply is higher than that of Canadian synthetic crude oil.

Blended bitumen has a very small market share in this region, making up only 3 000 m^3/d of the total Canadian crude oil deliveries. It is expected that if the light/heavy differential were to widen sufficiently, upgrades could be made to the refineries; however, the differential would have to be sustained for some time before this would occur.

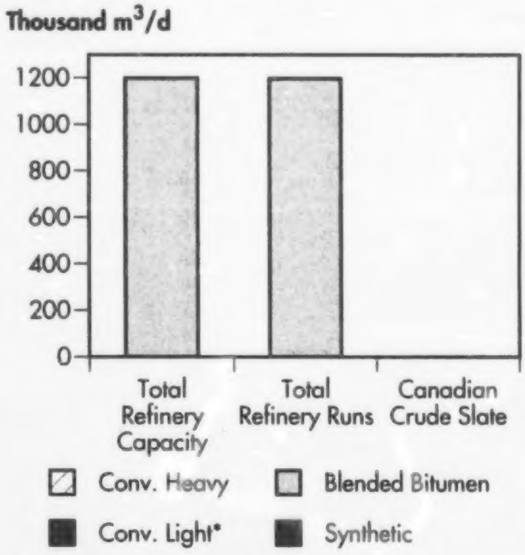
PADD III

PADD III has 50 major refineries, most of which are large and complex. This region has a refining capacity of 1 198 900 m^3/d (Figure 8.7). The crude oil slate of the PADD III refineries consists mainly of U.S. domestic crude oils and foreign imports. PADD III occasionally takes minor amounts of conventional light Canadian crude oil via tanker; however, as this is comparatively more expensive method to transport crude, it is unlikely that Canadian deliveries to PADD III will increase.

The U.S. Gulf is the primary source of domestic light sour conventional crude oil for the majority of the PADD III refineries. In addition, many of the refineries in this region have joint ventures with certain producing countries, and it is expected that indigenous and foreign crude oil will continue to be the main supply sources for PADD III.

FIGURE 8.7

PADD III Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

PADD IV

PADD IV has a combined refining capacity of 85 800 m^3/d (Figure 8.8). Canadian crude is transported via the Express/Platte pipeline, Rangeland/Conoco system and the Bow River/Cenex pipelines. PADD IV is land-locked, and as a result, receives all of its crude oil requirements from either local supply or Canada. Based on the Board's 1999 export statistics, nearly half of the slate of PADD IV refineries consists of Canadian crude oil. The Board believes that PADD IV could be capable of absorbing substantial amounts of unconventional crude oil, provided producers address the quality issues.

PADD IV can be divided into three market regions: Montana, Utah and Colorado/Wyoming.

Montana

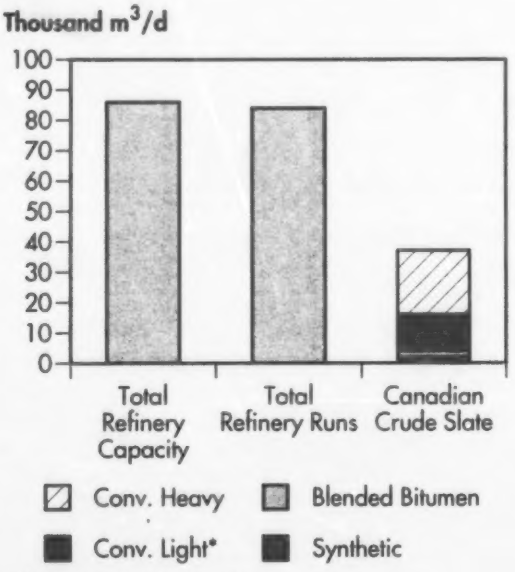
There are four major refineries in Montana:, Cenex, Conoco, ExxonMobil and Montana Refining. Together, they have a total refining capacity of about 28 000 m^3/d. As a result of its proximity to the producing areas of Canada, its land-locked status, as well as its accessibility by pipeline, this region takes a large amount of Canadian crude oil. In fact, over 75 percent of the crude oil processed in this region is Canadian. Of this volume, little synthetic crude oil was processed in 1999, although 2 200 m^3/d of blended bitumen was run.

It is projected that with the depleting indigenous supply, the demand for Canadian crude oil, especially synthetic crude oil and blended bitumen, will increase in this area. Combined with the upcoming Express spur line into the Billings area, over 3 000 m^3/d of synthetic crude oil could immediately be added to the crude diet of these refineries.

Blended bitumen will also be marketable in this area, as the refineries are reasonably complex, and able to process a heavier feedstock. In fact, 20 percent of the heavy crude oil run in Montana is blended bitumen.

FIGURE 8.8

PADD IV Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

Utah

Utah has a combined refining capacity of about 24 600 m^3/d, split amongst four refineries: BP Amoco, Chevron, Flying J and Phillips. The Utah refineries rely primarily on indigenous crude oil supply, running only 25 percent Canadian crude oil (about 5 740 m^3/d). However, local crude oil supply is declining at a rate of approximately four percent per year, and refiners will likely increase their synthetic crude oil diet from the 1999 quantities of 2 000 m^3/d if the quality improves.

Blended bitumen is not currently being processed in Utah to any great extent, as the refineries are relatively simple, capable of processing mainly light crude oils. Without significant upgrades, these refineries will not run heavier crude types.

Colorado/Wyoming

The five refineries in Colorado/Wyoming are: Conoco, Frontier, Little America, Sinclair Oil and Ultramar Diamond Shamrock have a combined refining capacity of around 33 200 m^3/d. In 1999, these refineries received more than 10 000 m^3/d of Canadian crude oil. Export statistics over the past two years show increasing volumes of both synthetic crude oil and blended bitumen moving into these refineries, and it is expected that there is some potential for additional market share as the PADD IV supply continues to decline.

PADD V

PADD V is a large region, with 26 refineries totalling 491 200 m^3/d of capacity (Figure 8.9). Of these refineries, only the seven located in Washington State regularly take Canadian crude oil, while the California refineries occasionally take spot volumes.

California

Very little Canadian crude oil is delivered into the California market. It is not accessible by pipeline; as a result Canadian crude oil must be delivered through the Trans Mountain pipeline to its Westridge dock facility, and shipped to the California refineries by tanker. Unless Canadian crude oil is discounted significantly compared with foreign and U.S. domestic supplies, it is unlikely that California will be a growth market for Canadian crude.

Washington State

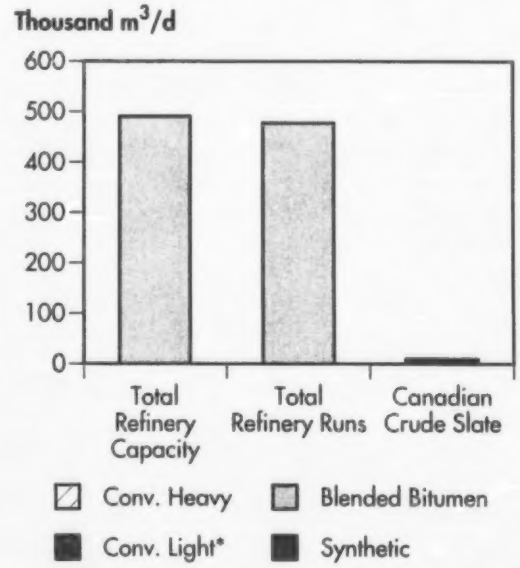
The Washington State refineries are owned by BP Amoco, Equilon, Sound, Tesoro, Tosco and U.S. Oil. The total refining capacity in Washington State is 105 600 m^3/d. Of this capacity, the refineries process about 10 000 m^3/d of Canadian light crude oil, and only small amounts of blended heavy.

The Washington State refineries typically run Alaskan North Slope (ANS). ANS is in decline, and these refiners will require additional crude oil to replace these volumes. It is possible that within five to seven years, synthetic crude oil will displace some ANS volumes. Until that time, Canadian light crude oil will compete based simply on economics.

It is doubtful that blended bitumen will find a market in Washington State refineries due to their current configuration and access to light conventional crude oils from both Alaska and foreign sources.

FIGURE 8.9

PADD V Receipts of Canadian Crude Oil - 1999



* Includes condensate and pentanes plus

8.4 Competition From Foreign Crude Oil Sources

Latin American crude oil is delivered into U.S. markets through the Gulf Coast. Venezuela has always provided competition for Canadian crude oil, and will soon be producing a sweet, bottomless crude oil that will likely be marketed in the Gulf Coast. Although the production costs of this new crude will be lower than those in Canada, it is assumed that its introduction will not lead to a decline in the overall market price of crude in this area, and therefore will not threaten the Canadian share of the PADD II market.

Both Mexico and Venezuela are large heavy crude oil producers, and Venezuela is expecting to produce a heavy sour synthetic crude oil. Historically, their delivered cost to Chicago is lower than that of Canada's. However, most exported Mexican and Venezuelan crude oil is committed to Gulf Coast refineries because of joint ventures. It is likely that the PADD II market will continue to represent only a small share of their production. PADD II will continue to be dominated by Canadian crude oil, and that it is unlikely that foreign producers will sacrifice Gulf Coast prices in order to penetrate the midwest market.

8.5 Overall Assessment of Available Markets for Synthetic Crude Oil and Blended Bitumen

This section includes a discussion of the key factors that are likely to play a role in determining whether the market can absorb the growing production of synthetic crude oil and blended bitumen. These include emerging trends in the international and North American markets as well as specific characteristics of the synthetic crude oil and blended bitumen markets. On the basis of these considerations, an overall assessment of the likelihood of markets being available will be provided.

Crude oil is being produced throughout the world at close to full capacity with the bulk of the spare capacity residing in OPEC. Of this, nearly all of the spare capacity is in Saudi Arabia, Kuwait and the United Arab Emirates, and most of it is medium/heavy sour crude oil. Given that the future growth in petroleum product demands will, for the most part, be for transportation fuels and that there is currently little spare desulphurization capacity, it is expected that there will, over time, be a widening of the light/heavy and sweet/sour crude oil price differentials. Such a widening of the differentials could provide the environment for refiners to install additional upgrading capacity to process incremental quantities of crude oil, including those from Canada.

It appears that at least one of Canada's main competitors recognizes that upgrading will be required. In this connection, Mexico recently announced an initiative designed to lighten its Maya heavy grade crude oil in the next three years in a bid to increase the number of refineries that can refine this feedstock. The process being studied involves subjecting Maya crude to hydrogen at high temperatures and pressure in the presence of a catalyst.

Refiners generally strive to increase output levels through improvements to internal processes and through ongoing minor investments. This results in small increases in refinery capacity, referred to as "capacity creep". This capacity creep factor in the U.S. has typically been about one to two percent per year and could provide for the processing of small additional quantities of Canadian synthetic crude oil and blended bitumen. As well, the demand for petroleum products is expected to increase at a rate of one and a half to two percent per year. This growth, coupled with the current high refinery utilization rates in the U.S., suggests that further refinery expansions can be expected.

Refiners in North America will be making significant investments in the coming years to meet the announced environmental regulations with respect to the sulphur content of motor gasoline and diesel fuel. In the course of planning their investments to achieve these targets, refiners will likely have the opportunity to assess and decide on the quality of crude oil they will process in the future. This could, in turn, allow for the efficient planning of the necessary upgrading investments that will be required to meet both the new product specifications and desired crude slate.

Refiners who are not familiar with the characteristics of synthetic crude oil are generally reluctant to process it. This reflects the fact that synthetic crude oil yields a higher proportion of middle distillates than other light crude oils, and that the distillate products processed are inferior in quality. Despite this, when refiners process synthetic crude oil on a test basis, the more complex refineries often find that it fits well into their crude slate.

Oil sands producers are continually seeking additional customers and looking for new approaches to market the growing volumes of synthetic crude oil. In this connection, solutions to the quality issue are being investigated. One possibility would be for producers to partially upgrade the synthetic crude oil at the source of production and for refiners to provide the balance of the upgrading at the refinery level.

The Board believes that there will be available markets for the growing volumes of synthetic crude oil contained in this assessment. There is likely to be some growth in Canada, both in the east and in the west. As well, there could be some additional markets in PADD V (i.e. mainly Washington State) as ANS supplies decline. PADD IV will be capable of processing substantially more synthetic crude oil in the coming years. PADD II will, however, be the main market for the growing synthetic crude oil outputs. The U.S. market could be capable of absorbing more synthetic crude oil than the quantities contained in the assessment, but this would likely require a significant price discount on synthetic crude oil relative to other light crude oils. If there were temporary periods when it became difficult to market the growing quantities of synthetic crude oil, there would be the option of placing some of the surplus in the Ontario market which currently imports more than 32 000 m^3/d of light sweet crude oil. The Board, however, does not believe that there will be a need to do this.

It appears that the marketability of the blended bitumen supply contained in the Board's projection is somewhat less certain than that for synthetic crude oil. It is possible that the announced projects may not all go ahead on the indicated schedules. Just recently, for example, Husky Oil announced that it was delaying, for the second time, the expansion of its heavy crude oil upgrader, stating that it was concerned about the significant new outputs that will be produced during the next several years. In terms of specific markets, there are some limited growth prospects in Canada, and PADD IV should be able to absorb additional quantities of blended bitumen. The bulk of the volumes, however, are expected to be marketed in PADD II.

The Board is of the view that temporary supply gluts or imbalances will likely exist from time to time as new in situ bitumen projects come onstream. It is expected, however, that this will result in a widening of the light/heavy crude oil price differential, which will, in turn, provide the incentive to install additional upgrading facilities. During the past ten years, there have been substantial upgrading investments made at the refinery level in the U.S., in the form of expansions to existing facilities and the installation of new coking equipment. It is expected that this trend will continue.

8.6 Conclusion

An opportunity for Canadian producers to sell their increasing outputs of synthetic crude oil and blended bitumen is developing in the North American marketplace. Product demands are growing and more crude oil will have to be processed to satisfy there requirements. As well, conventional light and conventional heavy crude oil production in both Canada and the U.S. is expected to decline during the projection period.

The Board's assessment of available markets for synthetic crude oil is that the increased production will likely be absorbed in the marketplace, although some price discounting relative to other light crude oils could be required. In the $22 Sensitivity, production of synthetic crude oil is about 14 percent higher than in the Base Case; the Board believes that these quantities could be marketed, but the price discount would likely have to widen. Marketing would not be an issue in the $14 Sensitivity because there would be substantially reduced production of synthetic crude oil.

In the case of blended bitumen, marketability appears to be somewhat less certain than that for synthetic crude oil, and it is conceivable that temporary supply imbalances could occur. The Board believes, however, that in these situations there would be a widening of the light/heavy crude oil price differential, which would provide the incentive to install upgrading facilities and, in turn, eliminate the supply imbalances. In the $22 Sensitivity, production of blended bitumen would be 30 percent greater than in the Base Case. In this situation, it is unlikely that the market could absorb these volumes. Again, marketing would not be an issue in the $14 Sensitivity because of significantly reduced output of blended bitumen.

CHAPTER NINE

ENVIRONMENT

9.1 Introduction

This chapter identifies a number of environmental issues associated with the oil sands industry, the main industry practices that contribute to these impacts, and the systems and practices that are used to manage these impacts.

Oil sands development processes can be loosely divided into the categories of mining, extraction, upgrading and in situ operations. Each of these processes has the potential to impact the environment. During surface mining, the primary environmental issues relate to land disturbance during exploration, site preparation and active mining, productivity and stability of reclaimed lands after the mine is decommissioned, surface and groundwater use and quality, and air emissions from mining equipment and the open pit. Environmental issues associated with extraction include air emissions from the extraction facilities and vehicles, storage and disposal of tailings, and wastewater from processed sand and tailings. For upgrading, the main environmental issues relate to air emissions and waste materials such as coke, wastewater and sulphur.

Bitumen may also be recovered by in situ techniques, in which steam or solvents are used to heat and dilute or extract the bitumen. The primary environmental issues associated with in situ recovery include land disturbance and habitat fragmentation during exploration, site preparation and operation (due to linear disturbances such as seismic lines, roads, pipelines, and the presence of well pads, facilities and utility corridors), air emissions, and surface and groundwater use and quality.

9.2 Regulatory Background

9.2.1 Regulatory Framework

Oil sands development in Alberta is regulated by both the EUB and Alberta Environment (AENV). The EUB operates under the legislative mandate of the *Energy Resources Conservation Act* and the *Oil Sands Conservation Act* (OSCA). AENV's authority is defined by the *Environmental Protection and Enhancement Act* (EPEA), the *Water Act and the Public Lands Act*. The legislation requires that both the EUB and AENV consider the environmental effects of proposed new or expansions to existing oil sands projects when their approval is required. In addition, the EUB and AENV both have responsibilities for the ongoing regulation of oil sands operations. To coordinate the responsibilities of these two regulatory bodies, a memorandum of understanding (MOU) was signed in 1996. The MOU describes the respective roles and responsibilities of the EUB and AENV in considering oil sands development applications and in regulating ongoing oil sands operations. The MOU includes a coordinated regulatory approval process to be used when applications require approvals under both

OSCA and EPEA. Although separate approvals are issued by the EUB and AENV, the application activities are integrated to ensure that they are conducted in a complementary, efficient and consistent manner.

Under its environmental assessment provisions, EPEA requires that an applicant for any oil sands mine or any upgrader producing greater than 2000 cubic metres of crude bitumen per day conduct an Environmental Impact Assessment (EIA).[1] In an EIA, the potential environmental effects of the proposed project are evaluated and, if applicable, mitigative measures are proposed to minimize the impacts. The EIA is submitted to AENV and is reviewed for completeness and for purposes of EPEA approvals by AENV. The EIA may also be submitted to the EUB as part of its oil sands approval process.

To determine if the proposal is in the public interest and should proceed, the EUB reviews, among other things, the economic, social and environmental effects of the project. The EUB review process may include a public hearing for applications that can not be easily resolved due to concerns or objections. If the EUB finds that the proposal is in the public interest, it issues a decision report and approves the application. AENV also issues approvals to establish, operate and reclaim oil sands developments. Both EUB and AENV approvals may impose measures to mitigate, avoid or compensate for possible adverse environmental effects as well as requirements and conditions under which the oil sands development must operate. Federal agencies may also participate in the provincial environmental assessment process as a responsible authority or interested party.

An application may also require an approval by an agency of the Federal Government, usually as a result of triggering the *Fisheries Act* or the *Navigable Waters Act* and hence the *Canadian Environmental Assessment Act* (CEAA). In the federal environmental assessment process, the review of the proposal could be subject to a screening or comprehensive study, and possibly a formal public review or mediation process. For example, Shell's Muskeg River mine project was subject to a CEAA screening by the Department of Fisheries and Oceans as a result of triggering the *Fisheries Act*.

9.2.2 Multi-Stakeholder Initiatives

Industry-regulatory-public working groups are important components of oil sands development and environmental management. Several regional groups have been established to study and propose options to address social and environmental impacts, including the following:

Wood Buffalo Environmental Association (WBEA)

The WBEA is a multi-party community-based association established to monitor air quality, including both ambient concentrations and receptor-based effects, in the Wood Buffalo region. Membership includes industry, First Nations, regional and provincial governments and environmental interest groups.

The Fort McKay First Nation was instrumental in establishing the WBEA. Fort McKay was concerned about environmental impacts to the community. Government and industry responded to Fort McKay's concerns by working with the community as members of the Air Quality Task Force. In 1987, the task force recommended ongoing dialogue and a consensus-based approach to air quality concerns and problem resolution. These recommendations resulted in the formation of the Regional Air Quality Coordinating Committee. In the spring of 1997, the committee changed its name to WBEA and became responsible for ownership and operation of a consolidated air quality monitoring network in the region. WBEA also expanded its mandate to include ecological and health effects monitoring. WBEA is an active participant in the Clean Air Strategic Alliance (CASA), which is an incorporated entity established in 1994 to manage air quality issues in Alberta. The regional air quality monitoring program developed by WBEA is part of CASA's provincial ecological effects monitoring program.

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[1] One cubic metre (m^3) of crude bitumen is approximately equal to 6.3 barrels or one metric tonne.

The Terrestrial Environmental Effects Monitoring Program is a sub-committee of WBEA. This program was designed to detect possible changes in soil chemistry and tree growth resulting from acidic deposition, as well as certain other indicators of environmental stress

Cumulative Effects Management Association (CEMA)

CEMA is a multi-stakeholder group established in 1997 to develop management systems to address the cumulative effects of regional development in northern Alberta. CEMA also provides an on going point of contact for issues related to cumulative effects. Regional stakeholders are able to contact CEMA to present new issues, or to voice concerns, questions or comments on the progress of regional issues.

As part of the CEMA initiative, industry and other stakeholders, including Environment Canada and Alberta Environment, established the NOx and SO_2 Management Working Group in 1999. The purpose of this group is to address concerns related to the cumulative effects of nitrogen oxides (NOx), sulphur dioxide (SO_2), and volatile organic compounds (VOCs), set appropriate ambient concentrations and regional carrying capacity guidelines, and develop management objectives including timelines and stakeholder responsibilities. It is expected that a management system for NOx and SO_2 emissions will be designed and established by 31 January, 2001.

There are several other regional initiatives which are addressing environmental issues related to oil sands, including:

- the Regional Aquatics Monitoring Program, which is a multi-stakeholder program with a mandate to monitor aquatic environments in the oil sands region;
- the Alberta Oil Sands Community Exposure and Health Effects Assessment Program, which collects field information on the exposure of residents in the Regional Municipality of Wood Buffalo to air contaminants, including information on health effects;
- the Heavy Metals Working Group, which has been established to study the issue of heavy metals deposition in the oil sands region, including the movement of heavy metals in the food chain. Five heavy metals specifically being studied are nickel, vanadium, mercury, aluminum and cadmium;
- the Sustainable Ecosystems Working Group, which was established to guide development and resource use in the region so that cumulative impacts do not exceed the carrying capacity of the environment. Three subgroups have been struck to help develop objectives for Wildlife, Biodiversity and Landscape components; and,
- the Surface Water and Fish Working Group, which will study the in-stream flow needs and integrity of the Muskeg River and other rivers and streams in the region. Activities may include conducting a scientific review of the methodology for in-stream needs for brown-water river systems.

Reclamation Advisory Committee (RAC)

RAC is a multi-stakeholder group established in early 1999 to follow-up on the direction and recommendations of the Oil Sands Mining End Land Use Committee. The purpose of RAC is to make integrated and regionally sound recommendations regarding reclamation and appropriate end land uses. The committee serves as a steering group for other working groups addressing various operational uses associated with oil sands mining, including the development of guidelines where needed.

Canadian Oilsands Network for Research and Development (CONRAD)

CONRAD is a collaborative research and development network established in January 1994. CONRAD is comprised of representatives from industry, government and academia and is funded by industry. Although the initial focus of CONRAD was directed at mining projects, the focus was later expanded to include in situ recovery. CONRAD now includes five technical planning groups (TPGs) for each of mining, extraction, upgrading, environmental and in situ recovery. Each TPG develops a project portfolio that may include fundamental research, exploratory research, technology development or research application. During its first four years of operations, CONRAD members invested approximately $52 million in research and development efforts.[a]

9.2.3 Policies and Guidelines

Oil sands development is also guided by policies and guidelines that are developed by regulatory agencies or the multi-stakeholder working groups. The *Regional Sustainable Development Strategy (1999)* creates a resource management framework for balancing development with environmental protection. Other examples of policies include the *Fort McMurray-Athabasca Oil Sands Sub-Regional Integrated Resource Plan (1996)* and the *Fish and Wildlife Policy for Alberta (1982)*. Examples of guidelines include the *Alberta Ambient Air Quality Guidelines (1997)*, the *Canadian Environmental Quality Guidelines (1999)*, the *Approaches to Oil Sands Water Release (1996)*, the *Guidelines for Reclamation to Forest Vegetation in the Oil Sands Region (1998)*, the *Land Capability Classification for Forest Ecosystems in the Oil Sands Region (1998)* and the *Guidelines for Wetland Establishment on Reclaimed Oil Sands Leases (2000)*.

9.3 Environmental Issues

9.3.1 Land

At an oil sands mining operation, land is disturbed during exploration and development of the open pit because surface vegetation and tree cover, topsoil, muskeg, sand, clay and gravel are removed. The construction of the plant and support infrastructure, such as roads and utility corridors, further disturbs the land. When mining operations are complete, the disturbed land must be reclaimed and remediated. Land is also disturbed during in situ operations as a result of seismic mapping, and the construction of wells and support infrastructure such as roads, pipelines and power line corridors.

Land Reclamation

The Alberta *Environmental Protection and Enhancement Act* requires oil sands operators to reclaim land that has been disturbed by oil sands operations so that it is capable of supporting the intended land uses. A major challenge when reclaiming land disturbed by mining operations is re-establishing self-sustaining ecosystems. To support such systems, the soil must contain the proper combination of salt, silt and clay, organic material and nutrients. Soil structure is also important as it affects soil properties and processes such as erosion, infiltration, water holding capacity, aeration, root penetration and mechanical strength. A common method used to reclaim a disturbed area is to cap it with a mixture of organic material (i.e. muskeg or peat moss) and underlying mineral materials. This reclamation mixture is placed over the materials to be reclaimed, primarily tailings sand and overburden. Placement over new materials such as consolidated/composite tailings is currently in the field pilot test stage.

Both Syncrude and Suncor continually reclaim soil materials and reconstruct mined-out areas. Trees and shrubs are planted and grasses are sown to prepare the land. To date, Syncrude has planted approximately 1.5 million seedlings in new landscapes. Since mining began in 1967, Suncor has planted approximately 2.4 million trees and reclaimed more than 600 hectares of land.

Biodiversity

Reclaiming land disturbed by oil sands operations includes the objective of re-establishing a diversity and abundance of habitats and qualities that is consistent with pre-disturbance levels. Ultimately, the region should form an ecosystem that has the equivalent capability to that which existed before development. It is anticipated that multi-stakeholder initiatives such as CEMA and AENV's Regional Sustainable Development Strategy will provide opportunities for issues such as wildlife management and changes in biodiversity to be addressed.

Habitat Fragmentation

In situ extraction is often regarded as environmentally superior relative to surface mining because it does not require the clearing of large surface areas or the excavation of overburden. However, disturbance to wildlife, wetlands and vegetation may result due to the network of seismic lines, roads, power line corridors, pipelines and other infrastructure required for project operation. This network of "linear disturbance" may result in habitat fragmentation, where extensive and contiguous ecosystems are broken up into fragments of various sizes and shapes. Habitat fragmentation can negatively affect sensitive species, and the roads or corridors also permit increased access for hunting and other recreational uses in areas which were formerly inaccessible.[b]

To address the concern of habitat fragmentation, in situ developers are looking to advancements in technology. For example, horizontal well schemes use 30 percent less surface land than that used in vertical well schemes.[c] Therefore, in situ developers may use multi-well pads with long horizontal segments to reduce overall surface disturbances to wildlife habitat and vegetation. Ongoing reclamation projects ensure that the duration of the surface disturbance is reduced. Operators are also developing project plans which avoid environmentally sensitive sites when establishing drilling locations and production facilities.

The in situ industry contends that these projects have fewer environmental effects than surface mining operations and are therefore preferable to mining operations. However, other groups, such as the Pembina Institute for Appropriate Development, disagree. Although they acknowledge that, on an individual basis, in situ projects may have fewer environmental effects than a surface mining operation, they are concerned that the cumulative impacts of widespread in situ projects could cause extensive impacts on large areas of the Province.[d] The EUB and AENV believe that multi-stakeholder initiatives such as the Regional Sustainable Development Strategy will be effective in addressing the regional environmental issues that may originate from continued development of in situ and surface mineable oil sands projects in northern Alberta.[e]

Tailings Management

Surface mining operations and subsequent water-based extraction of the oil sands produce large volumes of tailings. Tailings slurry from the extraction plants contain water, residual bitumen, sand, silt and clay, and solvent. The slurry is pumped into large settling basins or ponds, where the coarse sand quickly separates from the fine clays and silts. The silts and clays settle out to form a layer which consolidates very slowly. When this layer reaches 30 percent solids by weight (one to two years), it is known as "mature fine tails". At Syncrude, the company's combined tailings ponds hold 350 million cubic metres of unsettled sludge dating back to the mine opening in 1978, while Suncor has 90 million cubic metres of tailings to treat.[f]

The principle environmental threats from tailings ponds are the migration of pollutants through the groundwater system and the risk of leaks from tailings impoundments to the surrounding soil and surface water. To ensure that seepage from tailings ponds does not contaminate groundwater and surface water sources, tailings ponds are designed and constructed to guard against erosion, breaching and foundation creep over the long term.[g] In addition, monitoring programs for groundwater and surface water are conducted to ensure the integrity of the tailings ponds. Until recently, tailings ponds would likely be reclaimed by capping with water to form an artificial lake.

Recent research into reclamation options which would result in a dry landscape has resulted in the development of a treatment method which involves adding gypsum to a fine-enriched tailings slurry. *Consolidated or composite tailings* (CT) are a combination of coarse tailings (sand), mature fine tailings (silts and clays) and gypsum which results in a mixture that will not separate into the sand and clay components, but will quickly consolidate to release water (less than one year). This rapid water release leads to a consolidated dense tailings deposit (80 percent solids) within a short period of time and provides the opportunity to reclaim the tailings disposal area as a solid landscape.[h]

Oil sands operators, including Suncor, Syncrude and Shell, are currently using CT as their preferred tailings management strategy. However, this technology is still in the development stage, and better tailings management options may become feasible and economic in the future. Therefore, the EUB requires that operators submit annual progress reports on CT research and development activities until it is satisfied that a solid landscape can be achieved. It also requires operators to continue to test alternative tailings management technologies and submit progress reports on tailings research.[i]

One such alternative strategy currently under development is "thickened tailings" which is also known as "paste technology". With thickened tailings, tailings and liquid are combined with a flocculant to create a mix that is thicker than the traditional mix of water and tailings called "slurry." Because the tailings contain less water and are thicker, a smaller disposal area is needed for surface disposal than with a traditional tailings slurry. Also, thickened tailings solidify to a walkable state within a few days.

A combination of methods will likely be used to create the final reclaimed landscape. While the oil sands industry now has the technology to manage fine tailings, research and development will continue to improve the methods and make them more effective and more economical.

Wastewater Management

There are several sources of wastewater from oil sands operations. The sources of wastewater can be categorized as either operational wastewater or reclamation wastewater. Operational wastewater sources include CT release water, mine drainage, basal aquifer water, coker and upgrader wastewaters, sewage treatment system wastewaters and cooling waters. Reclamation wastewater sources include fine tails release water, and runoff and drainage from sand dumps, dykes, CT deposits, fine tails deposits, coke piles, and landfills and sulphur piles.

Under the Alberta *Environmental Protection and Enhancement Act*, oil sands operators must manage both reclamation and operational wastewater. Specific management strategies are required for each wastewater type based upon the timing and volume of the release, as well as the physical, chemical and toxicological characteristics of the wastewater. When wastewater is to be discharged into a waterbody, AENV requires that the quality of the wastewater discharge and the receiving waters be monitored to ensure that water of unsuitable quality is not released off-site. Management strategies may also involve treatment of the wastewater. For example, the main source of toxicity in the water phase of fine tailings are carboxylic acids (napthenic acids). There are two methods to treat fine tailings pond water undergoing research: bioremediation and electrocoagulation. With bioremedation, pond waters are treated with bacteria and nutrients under aerobic conditions. With electrocoagulation, electrical current is used to destabilize and remove dissolved and suspended solids, including organic compounds, inorganic salts and heavy metals.[j] CT release water, on the other hand, can be recycled back into the CT process. The increased volume of water recycled from the CT deposit reduces the need for river water use as make-up water in the extraction process.[k]

To address the issue of oil sands wastewater, government and industry formed the joint Oil Sands Water Release Technical Working Group. This group produced the report Approaches to Oil Sands Water Release in 1996, which provides government and industry with information and methodologies for the management of wastewater and can be used in the development of guidelines and operating procedures for wastewater management.

9.3.2 Water Use and Quality

Oil sands projects, both mining and in situ, require large volumes of water. Therefore, water use and conservation is an important issue in oil sands operations.

Surface Water

The primary source of surface water for oil sands extraction and upgrading operations is the Athabasca River, although other watercourses and waterbodies may be affected by channel removal or diversions depending on the location of the project. In order to use water, an operator must obtain a license from the province. This license stipulates the amount of water that can be withdrawn from the source, and water release quality and disposal rates. In addition, all oil sand operators are required to develop comprehensive water management plans.

At the completion of a mining operation, a lake may be created in the mined-out pit. These lakes are referred to as "end pit lakes". Oil sands operators ensure that all releases from end pit lakes will meet or exceed regulatory requirements. Monitoring programs have been or will be established to document activities and hydrological effects on watercourses related to mine operations and closure conditions. These programs are required to measure changes and to provide information so that operators can respond to such changes as necessary.

Groundwater

The primary groundwater issue related to surface mining is the depressurization of the basal aquifer. There are concerns that groundwater volumes may be affected by this depressurization. AENV requires that this issue be addressed in EPEA applications. Project-specific monitoring also occurs in order to measure the impact of mining operations on adjacent water bodies and wetlands.

For in situ projects, the primary groundwater issues relate to use of groundwater for steam injection/ bitumen recovery. With the anticipated increase in activity related to thermal projects, it is likely that there will be increased demand on groundwater resources. Consequently, it will be necessary to optimize the use of water by adopting processes which employ low steam-oil ratios. One such process is SAGD, which benefits from an improved steam-oil ratio and higher ultimate recovery in the order of 60 percent.[l]

There are also concerns about the impacts of in situ steam injection and bitumen removal on regional hydrogeology. Well drilling and operating practices are therefore reviewed continually in order to ensure that groundwater quality is not compromised. For example, well monitoring provisions have been included for certain operations to enable the early detection of well failures. Technological changes have also been used to address the concern of well failures. In 1994, the EUB directed the use of a special double-walled casing design, improved monitoring to detect failures and surface setbacks beyond the normal 100 metre provision.[m]

Another potential environmental issue associated with in situ development is the mobilization of heavy metals through the groundwater, possibly as a result of increases in water and sediment temperatures and pressures immediately adjacent to thermal injection. To address this issue, AENV is requiring operators of in situ projects to establish a groundwater monitoring system in order prevent and detect potential contamination of the groundwater system.

9.3.3 Air Emissions

Oil sands projects are large, use considerable amounts of energy and produce both gaseous and particulate emissions to the atmosphere. Air emissions are produced from mining equipment, from the open face of the mine, and from extraction and upgrading facilities. Utilities supplying electricity, water and steam to the mining, extraction and upgrading processes also produce emissions. For the in situ industry, air quality issues are primarily related to energy consumption during steam generation. Sources of air emissions in the oil sands industry also include infrastructure activities such as roads (traffic), pipelines, engines and buildings.

Greenhouse Gases

Greenhouse gases (GHG) are atmospheric gases such as carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) caused by natural events and human activities. There is generally a scientific consensus that climate change is associated with increasing concentrations of GHG emissions in the atmosphere arising from man made sources. For mining production, the main source of GHG emissions is the co-generation of electricity and steam for operations, the steam being used mainly in the extraction process that separates the bitumen from the sand. For in situ developments, the main source of CO_2 emissions is the generation of steam in thermal plants. The majority of methane emissions (90 percent) are from the venting of casing gas at satellite facilities. The remainder is from cleaning plants (nine percent) and wellheads (one percent).[n]

New technology and more efficient operations have greatly reduced emissions per unit of production. The expansions of the Syncrude and Suncor plants provided the opportunity to adopt the new technologies that have been developed through research and development. Syncrude, for example, predicts that its GHG emissions per unit of production will be 38 percent lower by 2008 compared to 1990 emissions.[o] The lower per unit emissions anticipated at both plants arise from:

- replacing electricity intensive drag lines and bucket wheels with truck and shovel mining;
- hydrotransport of the ore instead of the use of conveyors;

- switching to low temperature extraction methods, thereby greatly lowering energy needs;
- improving energy integration between extraction and upgrading and onsite electricity generation;
- adding co-generation using natural gas;
- not increasing coke use;
- using waste heat recovery systems; and,
- implementing leak detection and repair programs.[p]

At the same time that more efficient technology is being adopted, synthetic crude oil quality is improving. The synthetic crude oil can displace conventional light crude oil at refineries. Due to its residue-free nature, little heavy fuel oil and coke are produced. This in turn allows for greater use of natural gas in the refining process which subsequently reduces GHG emissions.

Although GHG emissions per unit of synthetic crude oil production have been greatly reduced, an increase in production could lead to an increase in total emissions. For example, Syncrude's total oil production is expected to more than double by 2008 leading to an overall increase in GHG emissions. Suncor acknowledged that "doubling oil sands production will increase GHG emissions from our operation."[q] Actions being taken by industry to limit GHG emissions while increasing production include:

- implementing new, energy-efficient technologies in both existing operations and new operations;
- capturing vented methane and reducing flaring of solution gas;
- developing alternative and renewable sources of energy;
- pursuing GHG offsets;
- supporting environmental and economic research; and,
- educating and engaging employees, customers and communities on climate change.

GHG emissions were estimated for the production of bitumen and synthetic crude oil by the oil sands sector and are shown in Figure 9.1.[1] The predicted emissions are a result of the supply projections contained in this report. As stated in Chapter 6, the Board's oil sands supply projections are broadly based on discussions with industry combined with the Board's own analysis. The assumptions used in this report to estimate GHG emissions are the same as those contained in the Board's 1999 Supply and Demand report.[r] The methodology is based on a study conducted by the Canadian Association of Petroleum Producers (CAPP), with further development by CAPP and Environment Canada. The total emissions of GHG are generated by applying emission factors for each greenhouse gas to the supply projections. The emission factors are for the most part obtained from Environment Canada and Natural Resources Canada. The approach uses a model developed by

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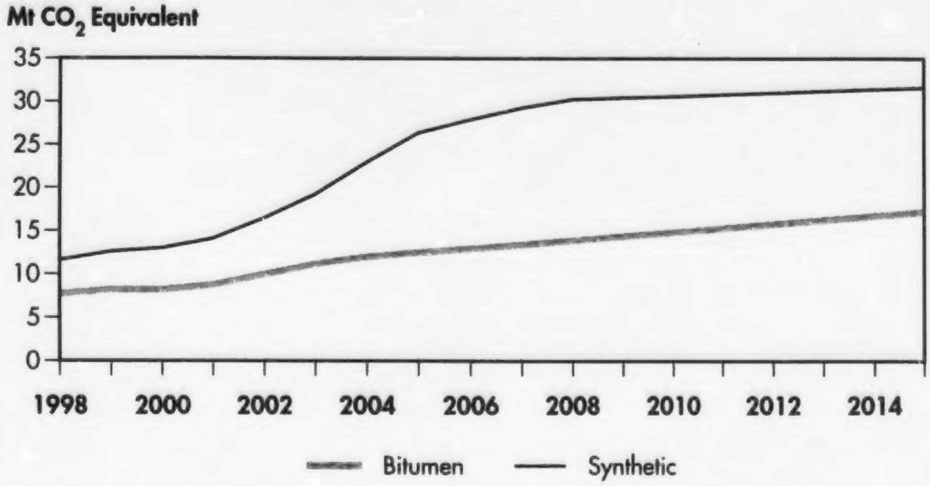
[1] Although CO_2 is the predominant anthropogenic greenhouse gas, CH_4 and N_2O have a stronger impact, molecule for molecule, on warming the atmosphere. These gases are therefore compared to CO_2 by using the Global Warming Potential (GWP) value, which is defined as the measure of the warming effect that a gas has on the atmosphere, relative to CO_2. The GWP of CH_4 is 21 and that of N_2O is 310. Emissions of these gases are multiplied by their respective GWP to obtain a CO_2 equivalent

FIGURE 9.1

Estimated Greenhouse Gas Emissions



Natural Resources Canada. Commitments made by companies to reduce their emissions under the Voluntary Challenge Registry[1] program are explicitly included in the model.

Emissions of GHG in 2000 are predicted to be 13.0 mega-tonnes (Mt) from synthetic crude oil production and 8.2 Mt from bitumen production. By 2015, synthetic crude oil emissions are predicted to be 31.7 Mt, while bitumen emissions are predicted to be 17.2 Mt. These estimates are similar to those found in the report *Canada's Emissions Outlook: An Update*[5]. In that report, emissions of GHG in 2000 were estimated to be 13.6 Mt from synthetic crude oil production and 8.1 Mt for bitumen. By 2015, emissions of GHG were estimated to be 30.5 Mt for synthetic crude oil and 18.8 Mt for bitumen.

Sulphur Dioxide (SO_2)

The burning of petroleum coke or produced gas to produce steam and electricity, the use of diesel equipment and the upgrading of bitumen result in emissions of SO_2, which can be chemically transformed into acidic pollutants such as sulphuric acid (leading to acidification of soils and water bodies). Emissions of sulphur compounds and hydrocarbons can also contribute to urban smog and affect local air quality.

In Alberta, operators who emit SO_2 are expected to meet the requirements of Alberta's *Ambient Air Quality Guidelines* for SO_2. They are also expected to participate in multi-stakeholder air quality forums and to contribute to air quality management through compliance and corporate stewardship.

New and improved technology has greatly reduced emissions of SO_2. Although oil production has more than doubled, annual SO_2 emissions have not increased; in fact, Suncor's emissions are at an all-time low. The biggest contributor to lower SO_2 emissions at Suncor was the flue gas desulphurization plant, which completed its first year at capacity operation in 1998. The plant removes approximately 95 percent of SO_2 emissions produced as a result of burning coke to generate electricity and steam.[i] A similar result is expected at Syncrude, where new equipment such as a flue gas desulphurization unit added to the upgrader, along with a sulphur plant and sour water treater, will all contribute to reducing the total volume of SO_2 emissions, even though production will more than double.

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[1] The Voluntary Challenge and Registry (VCR) was established in 1995 as an element of Canada's National Action Program on Climate Change. Its purpose is to encourage private and public sector organizations to voluntarily limit their net greenhouse gas emissions as a step towards meeting Canada's climate change goals. The VCR publicly records the commitments, progress and achievements of all VCR Inc. registrants, including the Action Plans and Progress Reports that form the basis for the GHG emission reduction activities planned by organizations. More than 900 organizations have joined the initiative since 1995.

Nitrogen Oxides (NOx)

NOx (NO_2 and NO) is produced by the burning of fossil fuels and contributes to the acidification of soils and water bodies. NOx can contribute to the formation of ground-level ozone through a complex photochemical reaction with volatile organic compounds. In the oil sands industry, NOx sources include diesel engines, extraction and upgrading plants, cogeneration facilities and fixed sources such as gas fired heaters and boilers.

NOx is also a compound for which air quality guidelines have been developed. In Alberta, operators who emit NOx are expected to meet *Alberta's Ambient Air Quality Guidelines* for NO_2. They are also expected to participate in multi-stakeholder air quality forums and to contribute to air quality management and monitoring through compliance and corporate stewardship.

Industry is using new technology and improvements in equipment in order to control NOx emissions. For example, the use of low NOx burners, natural gas for incremental power generation, and low-emissions mine fleet technology all contribute to lower NOx emissions. Both Suncor and Shell are committed to using low-emissions engine technology even if it is not required by Canadian regulations. Suncor, for example, plans to implement low-emissions mine fleet technology as it retires its 240-ton mine trucks and expects that NOx and particulate matter emissions of its mine fleet could be reduced by 30 to 40 percent by using the improved technology.[ii]

Volatile Organic Compounds (VOCs)

VOCs are carbon-containing compounds that can cause odours and may combine with other gases to form ground-level ozone and other photochemical oxidants. VOCs also contribute to the formation of particulate matter. In addition, many VOCs are toxic themselves. The VOCs that react with NOx to form ozone include ethylene, propane, butane and BTEX (benzene, toluene, ethylbenzene and xylene). In the oil sands industry, VOC sources include tailings ponds, extraction plant vent, and fugitive emissions from process tank areas, tank farms and the exposed mine face.

In Alberta, operators who emit VOCs are expected to participate in multi-stakeholder air quality forums and to contribute to air quality management through compliance and corporate stewardship. Forums such as the Canadian Council of Ministers of the Environment have also been used to develop some codes to manage emissions of these compounds. In addition, CAPP has also established a best management practice protocol for the control of benzene.

VOC emissions are being managed by process changes and technology improvements. For example, in EUB Decision 99-2, Shell committed to using either technological or operational-based means to improve solvent recovery from the extraction process. Shell will use a light hydrocarbon solvent to remove residual solids and water from the extracted bitumen. The solvent contained in the tailings will be recovered by using solvent recovery units and re-used to ensure that the amount of unrecovered solvent going to the tailings ponds is minimized, thereby reducing fugitive emissions of VOCs.

Ozone

Ground-level ozone is a colourless gas that forms just above the earth's surface. It is formed when NOx and VOCs react in the presence of warm temperatures and sunlight. Ground-level ozone is a major component of smog, which when inhaled can lead to adverse health effects such as respiratory problems. Ozone not only affects human health, but can also damage vegetation, decrease the productivity of some crops, and may contribute to forest decline. Ozone can also damage synthetic materials and some textiles, cause cracks in rubber, accelerate fading of dyes and speed up deterioration of some paints and coatings.

Although oil sands production is not a direct source of ozone, the release of NOx and VOC emissions in the presence of certain meteorological conditions could contribute to ground-level ozone formation. Because of the cumulative effects of industrial emissions, Environment Canada has identified the need for regional ozone management. It therefore supports the AENV's Regional Sustainable Development Strategy initiative as an appropriate multi-stakeholder forum to manage regional air quality in the oil sands region. The EUB also expects that oil sands operators, in collaboration with the WBEA, AENV and other stakeholders, will continue to compile information regarding ozone formation from precursor compounds and any associated impacts on potential ozone receptors.[v]

Particulate Matter

Particulate Matter (PM) is composed of micron-sized solid and liquid matter small enough to be suspended in air. Depending on their size, these particles can be inhaled and trapped in the airways and lungs, leading to adverse health effects. PM can also lead to urban smog, reduced visibility and can contribute to the acidification of soils by entrapping NOx and SO_2. In the oil sands industry, sources of PM include windblown soil, road dust and industrial activities as well as motor vehicles and power plant emissions. Secondary sources of PM include emissions of SO_2, NOx and VOCs, which act as precursors to particulate formation in the atmosphere.

Both Alberta and Canada have ambient air quality objectives for total particulate matter. Recently, PM less than or equal to 10 microns in size ($PM \leq 10$) was declared toxic under the *Canadian Environmental Protection Act*. The Federal Government now has the authority to develop strategies for the control of PM. The government has two years to develop control measures to reduce exposure to $PM \leq 10$ and a further 18 months to implement the measures.

In the oil sands industry, emerging low emissions engine technology has the potential to significantly reduce PM and secondary PM precursor emissions. Other efforts to reduce PM focus on process redesign, such as the use of electrostatic precipitators. Oil sands operators, through their participation in the WBEA and other multi-stakeholder forums, also ensure that appropriate air monitoring programs for communities adjacent to oil sands operations are established and maintained.

9.3.4 Cumulative Environmental Impacts

The nature of the numerous oil sands projects being planned can strain the regulatory system designed to address environmental impact assessment and approvals. The challenge of these projects lies in the fact that these large developments lie adjacent to each other. The activity level raises the question of how the numerous projects, in close proximity, will collectively and cumulatively interact with the environment.[vi]

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The potential for regional impacts generated from existing, approved and planned oil sands projects became a key issue in the spring of 1997 during the public pre-hearing meeting for the Syncrude Aurora Mine application. Noting that potential conflicts may occur from several mines and associated facilities developing at the same time, Environment Canada recommended that stakeholders in the oil sands region consider opportunities for collaborative actions. At the same hearing, the Department of Fisheries and Oceans encouraged a regional forum for industry and stakeholders to ensure that site-specific plans for the protection and mitigation of fish and fish habitat were adequate.[4]

In December 1997, Shell Canada submitted its proposal for its Muskeg River Mine Project to the EUB. This was followed by Suncor's Millennium Project application in April 1998 and Syncrude's Mildred Lake Upgrader Expansion Project application in July 1998. To respond to the important challenges related to cumulative effects assessment (CEA), the oil sands industry established the Athabasca Oil Sands Cumulative Effects Assessment Initiative. A result of this initiative was the *Athabasca Oil Sands CEA Framework Report* which was released in February 1999. It described a common framework for conducting cumulative environmental effects assessments of oil sands projects in the oil sands region.

In September 1998, AENV led the development of the Regional Sustainable Development Strategy (RSDS) for the Athabasca oil sands region. The development of the RSDS involved a partnership with stakeholders and regulators, including industry, First Nations and Aboriginal communities, environmental interest groups, local business groups, and municipal, provincial and federal government agencies. The RSDS was based upon 72 environmental issues compiled from the *Athabasca Oil Sands CEA Framework Report*, from project-specific environmental impact assessments in the region, and from issues raised during EUB hearings on oil sands mining and in situ projects. The issues were grouped into 14 themes, which were then divided into three categories based on the priority in which stakeholders wanted to see them addressed. For issues in each theme, there are groups designing management strategies including monitoring and research programs. The intent of the RSDS is that data will be shared to ensure comprehensive decision making at all levels. Where objectives and indicators are complex and difficult to determine or measure, regional stakeholders representing scientific, traditional, industrial, public and regulatory interests will work together to develop a common understanding and agreement on the management system. AENV will deliver overall coordination and leadership of the RSDS. CEMA will provide a point of contact for regional stakeholders regarding new issues, concerns, questions or comments. Both AENV or CEMA will track the progress of issues.[5]

RSDS Categories and Themes:

Category A *(based on information gaps and urgency)*: sustainable ecosystems and land use; cumulative impacts on wildlife, soil and plant species diversity; effects of all air emissions on human health, wildlife and vegetation; and effects of heavy metals deposition - bioaccumulation and consumption.

Category B *(based on information gaps and work underway)*: access management; cumulative impacts on fish habitat and populations; effects of tailings pond emissions; effects of acid deposition on sensitive receptors; and cumulative impacts on surface water quality.

Category C *(based on information gaps, work underway and lower level of urgency)*: end pit lake water quality; cumulative impacts of surface water quantity; cumulative impacts on groundwater quantity and quality.

9.3.5 Socio-Economic Effects

The key socio-economic issues relating to oil sands development include:

- increases in regional employment, leading to changes in population dynamics;

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The key socio-economic issues relating to oil sands development include:

- increases in regional employment, leading to changes in population dynamics;

- impacts on First Nations, Métis peoples and traditional land use;
- impacts on local and regional service providers including the areas of housing, education, health services, social services and emergency services;
- impacts on transportation and other infrastructure such as utilities and bridges;
- project-specific employment and contracting issues; and,
- economic benefits to the regional, provincial and national economies.

Socio-economic issues are being addressed primarily through two groups: the Regional Infrastructure Working Group and the joint Athabasca Tribal Council/Athabasca Resource Development Working Group.[2]

The main purpose of Regional Infrastructure Working Group is to identify priority items relating to physical and social infrastructure, determine the appropriate authority to initiate action, and forward information to assist with planning and resolving these items. Membership includes oil sands developers, community groups and the Regional Municipality of Wood Buffalo. For particular issue areas, the working group will strike a subcommittee and invite stakeholders to become members of these subcommittees.

The Athabasca Tribal Council/Athabasca Resource Development Working Group was established to address development impacts on aboriginal people. The primary impact of oil sands development on aboriginal people is the effect on the traditional way of life. Traditional lands are being affected by industrial and lumber activities, resulting in the reduced ability of the land to sustain the traditional ways of life. Other issues include education, training, employment and business opportunities, retention of culture, adjusting to a wage economy, and physical infrastructure during both construction and operation of the oil sands project. A sub-committee will provide linkage to CEMA.

Socio-economic issues are also addressed during the EUB approval process. As part of this process, project proponents are required to conduct public consultation with stakeholders, including aboriginal groups in the impacted communities or within the project areas. Companies may enter into agreements with stakeholders, particularly the aboriginal groups, if they deem it beneficial in resolving issues identified during the public consultation process. Many companies also have aboriginal policies and programs in place to enhance benefits to aboriginal groups. These programs may encompass the areas of education, employment, business development, community development and environmental issues, particularly the understanding of cumulative environmental effects on traditional lands.

9.4 Conclusion

Alberta's oil sands resources are vast. The increasing project development currently underway or proposed will bring with it many challenges for the industry, the public and the regulators. Careful planning is required to ensure that no irreparable damage is done to the people and the environment, and that natural resources are developed in a sustainable manner taking into account the needs of the future generations. Although, in general, technological improvements have reduced environmental impacts on a per unit basis, cumulative environmental impacts may increase as overall production increases. The many multi-stakeholder groups established over the last several years will be critical to managing the cumulative effects of increasing development in the oil sands region. In addition, the RSDS and subsequent development of management systems, a new and innovative approach to managing the cumulative effects of an industry, will need to be closely scrutinized for their effectiveness.

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GLOSSARY

Apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
Aquifer	An underground geological formation, or group of formations, containing water.
Associated Gas	Natural gas which overlies and is in contact with crude oil in the reservoir.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 Imperial gallons.
Biodiversity	The variety of living components in an ecosystem.
Bitumen or Crude Bitumen	A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Blended Bitumen	Crude bitumen to which light oil fractions have been added in order to reduce its viscosity and density to meet pipeline specifications.
Cetane Number	A number for designating the percentage of pure cetane in a blend of cetane and alphamethylnapthalene that matches the ignition quality of a diesel fuel sample. This number, specified for middle distillate fuels, is synonymous with the octane number of gasolines.
CH_4	Methane.
CO_2	Carbon dioxide.
Coke	A solid black carbon residue remaining after valuable hydrocarbons are extracted from bitumen.
Coker	A vessel in which bitumen is cracked into its fractions and coke withdrawn to start the conversion of bitumen into upgraded crude oil. The lighter fractions, primarily naphtha and gas oils, become the main ingredients of the final blend.

Composite Tails (CT)	Also known as consolidated tails. This technology combines fine tailings with gypsum and sand as tailings are deposited. The mixture causes the tailings to settle faster, enabling final reclamation to occur sooner.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a processing plant before the gas is processed in a plant.
Conventional Crude Oil	Crude oil which, at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Cracking	The process of breaking down the larger, heavier more complex hydrocarbon molecules into smaller, lighter molecules.
Cyclic Steam Stimulation	CSS is a method of recovering bitumen from a reservoir using steam injection to heat the reservoir to reduce the viscosity of the oil and provide pressure support for production. Oil production occurs in cycles, each of which begins with a period of steam injection followed by the same well being used as a producer.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Ecosystem	A biological community of interacting organisms and their physical environment.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from the oil sands.
Fossil Fuels	Hydrocarbon based fuel sources such as coal, natural gas, natural gas liquids and crude oil.
Greenhouse Effect	A naturally occurring phenomenon in the earth's atmosphere in which incoming solar short-wave radiation passes relatively unimpeded, but long-wave radiation emitted from the warm surface of the earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperature.
Heavy Crude Oil	Generally, a crude oil having a density greater than 900 kg/m^3.
Horizontal Well	A well which deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.

Hydrocarbons	Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, gaseous or solid.
Hydrocracking	The breaking of hydrocarbon chains into smaller molecules in the presence of hydrogen and a catalyst such as platinum. The end result is a high quality gasoline and other light hydrocarbons.
Hydrotreating	A process used to saturate olefins and improve hydrocarbon streams by removing unwanted materials such as nitrogen, sulfur, and metals utilizing a selected catalyst in a hydrogen environment.
Integrated Mining Plant	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
In Situ Recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Light Crude Oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.
Muskeg	A water-soaked layer of decaying plant material, one to three metres thick, found on top of the overburden. Muskeg supports the growth of shallow root trees such as black spruce and tamarack.
Natural Gas Liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, and pentanes plus.
NOx	Oxides of nitrogen.
Oil Sands	Sand and other rock material which contain bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Overburden	The layers of sand, gravel and shale which overlie the oil sand and must be removed before mining can begin. Overburden underlies the muskeg in many places.
PADD	Petroleum Administration for Defence Districts.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Real Price	The price of a commodity after adjusting for inflation. In this report most real energy prices are expressed in 1997 dollars.

Reclamation	Returning disturbed land to a stable, biologically-productive state.
Recovery - Improved	Improved or enhanced recovery is the extraction of additional crude oil from reservoirs through a production process other than primary recovery.
Recovery - Primary	The extraction of crude oil from reservoirs utilizing the natural energy available in the reservoirs and pumping techniques.
Reserves - Established	The sum of the proven reserves and half probable reserves.
Reserves - Initial Established	Established reserves prior to deduction of any production.
Reserves - Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves - Remaining	Initial reserves less cumulative production at a given time.
Reservoir	A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil that is confined by impermeable rock or water barriers.
Resources - In Place	The gross volume of crude oil estimated to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.
Resources - Recoverable	That portion of the ultimate resources potential recoverable under expected economic and technical conditions.
Resources - Ultimate Potential	An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology.
SAGD	Steam-Assisted Gravity Drainage is a steam stimulation technique using horizontal wells in which the bitumen drains, by gravity, into the producing wellbore. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Smoke Point	A test measuring the burning quality of jet fuels, kerosene, and illuminating oils. It is defined as the height of the flame in millimeters beyond which smoking takes place.
Stand Alone Upgrader	An upgrading facility that is not associated with a mining plant or a refinery.
SO_2	Sulphur dioxide

Supply Cost	Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
Synthetic Crude Oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Unconventional Crude Oil	Crude oil which is not classified as conventional crude oil (e.g., bitumen).
Upgraded Crude Oil	Generally refers to crude bitumen and heavy crude oil that have undergone some degree of upgrading, but is commonly synonymous with synthetic crude oil.
Upgrading	The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
VAPEX	Vaporized Extraction is a process similar to SAGD but using a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
Viscosity	The measure of the resistance of a fluid to flow. The lower the viscosity, the more easily a liquid will flow.
Volume - Initial In Place	The volume of crude bitumen or crude oil currently interpreted to exist before any production.
Volume - Ultimate In Place	A value representing the volume expected to ultimately be found by the time all exploratory and development activity has ceased.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

EUB RESOURCE ESTIMATION METHODOLOGY

The EUB originally calculated the in-place volume of crude bitumen using a volumetric methodology called the Building Block Method. On a quarter section basis, over the entire deposit and for each horizon containing bitumen, a volume was determined where the minimum cut-offs were exceeded. These cut-offs are three percent bitumen by weight and 1.5 metres of net pay for the sandstone reservoirs in the in situ recovery areas and six percent and 3.0 metres pay for the surface mining areas; and 30 percent bitumen by volume and five percent rock porosity for the carbonate reservoirs. The data for each quarter section was taken from drill holes, or inferred from the lowest value of surrounding lands. A standard volumetric determination was made by:

$$\text{Bitumen volume} = \left(\frac{\text{net pay x weight percent bitumen x bulk density}}{100}\right) \text{x (area)}$$

More recently, a mapping program has been used to generate a pay thickness map of each horizon in a deposit. The produced rock volume is reduced to the weight or volume bitumen content. This is the same method applied to gas or oil pools in the rest of the province.

Recoverable bitumen volumes are determined separately for those areas that can be accessed by surface mining and those areas where recovery must be through in situ methods.

a) Surface mining methods are assumed for those areas where the overburden thickness is 75 metres or less. After application of cut-offs for minimal bitumen saturation and thickness, the total surface mineable volume was reduced by 10 percent to allow for environmental corridors along the major rivers, 10 percent for isolated ore bodies which are not likely to be developed, 10 percent for surface facilities (plants, tailings ponds, and waste dumps) and 18 percent for mining/extraction losses. Prior to 1999, the EUB counted only the volumes in the active mine sites as reserves (the remainder being a resource). Since then, they have assumed that all of the mineable areas (less the previously stated losses) are developable and the previous resource volumes are now counted as reserves.

b) Prior to 2000, for in situ methods, the EUB only counted reserves for active commercial projects, primary recovery schemes and experimental recovery schemes. Starting in 2000, the EUB has determined reserves for those areas that are deemed to be amenable to in situ recovery methods. In-place cut-offs for thermal projects are increased to a minimum thickness of 10 metres. An estimated recovery factor of 20 percent is applied to thermal projects and five percent for primary recovery areas, which are less than some of the current projects to better reflect the uncertainties involved. On an annual basis, the recovery factors may have to be adjusted to reflect actual recovery information for the various recovery schemes.

SUPPLY COSTS FOR SAGD

TABLE A2.1

Economic Assumptions

Supply Cost	1) Full cycle supply cost - is the price at the field location needed to exactly balance revenues with capital investments, operating costs, royalties and taxes, and a 10 percent return over the 30 year project life, except land costs. 2) Expressed as an average cost per barrel of oil production at the source field locations.
Rate of Return	10 percent
Royalty	Alberta Oil Sands regime
Federal Taxes	Current Oil Sands terms
Provincial Taxes	Current Alberta rates
Project Sizes	3 000 to 16 000 m^3/d
Natural Gas Prices	C\$2.00 - C\$5.00 /GJ

The estimates are calculated using cash flow model PEEP for assessing Athabasca McMurray and Cold Lake Clearwater formations, and several different commercial production scales ranging from 3 000 to 16 000 m^3/d. It is assumed that each case is a stand-alone project and independent of other development projects.

Capital costs include reservoir delineation, drilling and completion of well-pairs, site preparation, and central facilities. It is assumed that well pairs are drilled from common pads and are positioned with the injection well directly above the production well.

TABLE A2.2

Reservoir and Bitumen Characteristics

Oil Sands Area	Athabasca	Cold Lake
Oil Sands Deposit	McMurray	Clearwater
API ^{0}	8	10
Porosity (percent)	26 - 28	30
Aquifer	No	No
Well Pair Profile	Figures 1 & 2	Figures 3 & 4

FIGURE A2.1

Well-Pair Performance Profile - High Quality Athabasca; No Water Zone

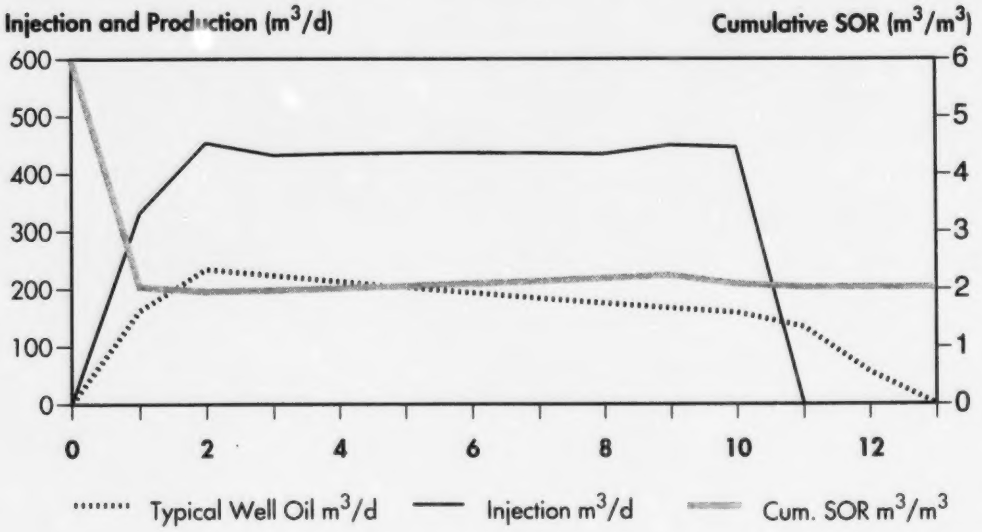


FIGURE A2.2

Well-Pair Performance Profile - High Quality Cold Lake; No Water Zone

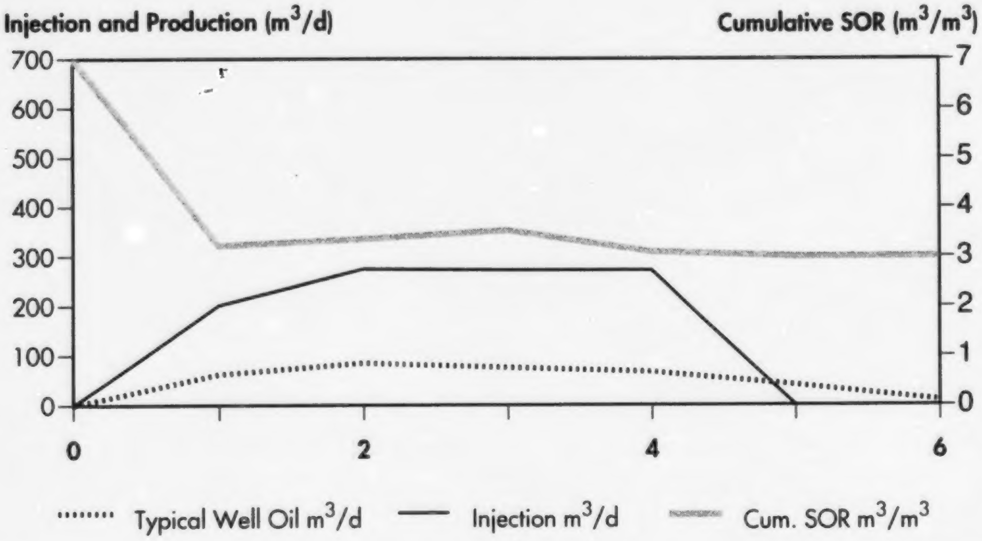


FIGURE A2.3

Well-Pair Performance Profile - Low Quality Athabasca; No Water Zone

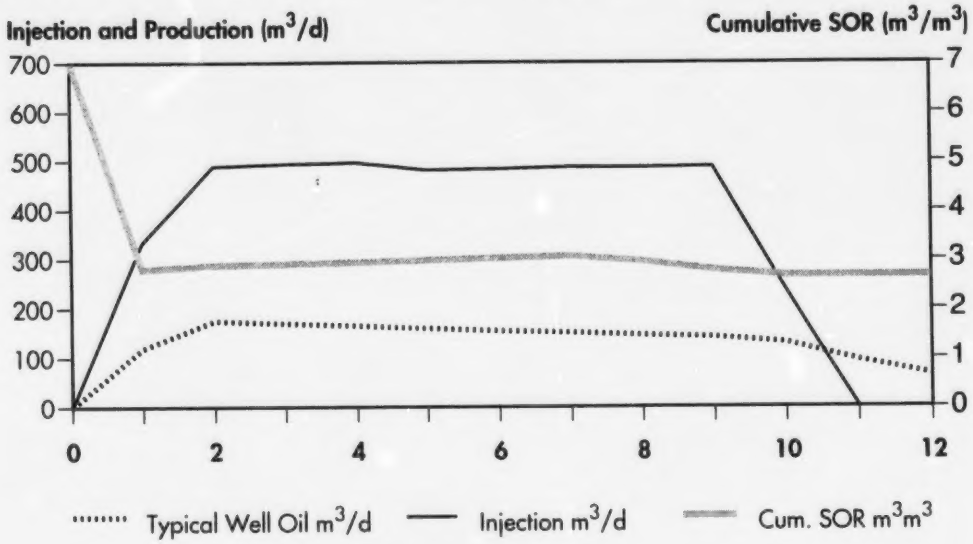
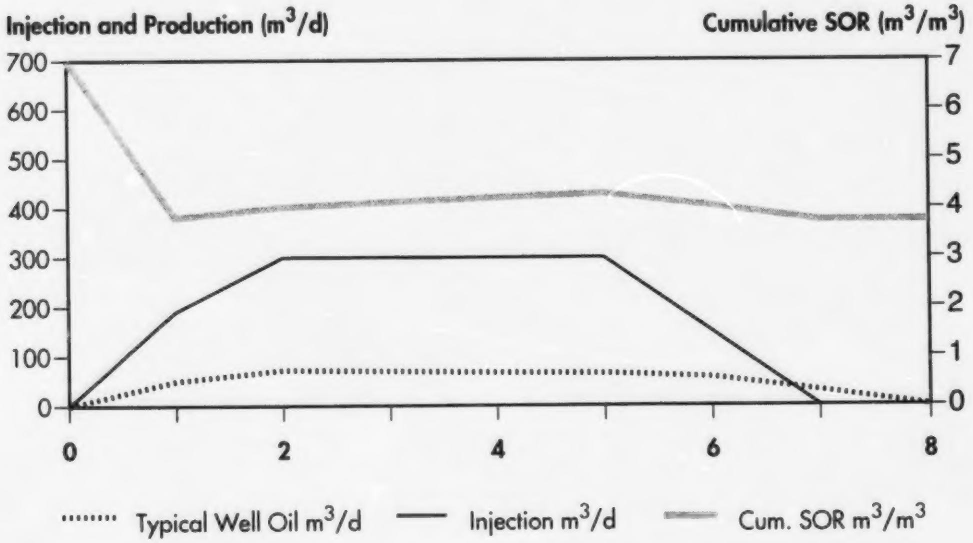


FIGURE A2.3

Well-Pair Performance Profile - Low Quality Cold Lake; No Water Zone



ECONOMIC INDICATORS, CANADA

TABLE A3.1

World Oil Price WTI (US$[1997]/barrel)(1)	1997	1998	1999	2000	2001	2002	2005	2010	2015
Base Case	20.69	14.24	18.6	26	22	18	18	18	18
$14 Sensitivity	20.69	14.24	18.6	26	20	14	14	14	14
$22 Sensitivity	20.69	14.24	18.6	26	24	22	22	22	22
Consumer Price Index (1997=1.0)	1	1.02	1.04	1.06	1.08	1.1	1.16	1.28	1.42
Cdn$ in U.S. funds	0.72	0.68	0.67	0.68	0.71	0.72	0.74	0.76	0.77
Canada Real GDP Growth %	3.8	3.1	3.7	3.2	3	2.9	2.5	2.1	2.1

1 West Texas Intermediate crude oil price at Cushing, Oklahoma.

APPENDIX FOUR

CONVERSION TABLE

Abbreviation Table

Prefixes		Equivalent
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Imperial/Metric Conversion Table

Physical Units		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil, LPG) 35.3 cubic feet (gas)
L	litre	0.22 imperial gallon
b	barrel (oil, LPG)	0.159 m^3

Energy Content Table

Energy Measures		Energy content
GJ	gigajoule	0.95 million BTU
PJ	petajoules	

Electricity		Energy content
MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ

Natural Gas		Energy content
Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ

Energy Content Table

Natural Gas Liquids		Energy content
m^3	Ethane	18.36 GJ
m^3	Propane	25.53 GJ
m^3	Butanes	28.62 GJ

Crude Oil		Energy content
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ

Greenhouse Gas Emission Factors

	Energy Production Sources	
Combustion Sources	Bitumen Production	Oil Sands
CO_2	439.2 kg/m^3	741.2 kg/m^3
CH_4	25.04 kg/m^3	42.47 kg/m^3
N_2O	2.45 kg/m^3	8.56 kg/m^3